PB83-101337

Acid Rain Mitigation Study. Volume III Industrial Boilers and Processes

Radian Corp.
Austin, TX

Prepared for

Industrial Environmental Research Lab.
Research Triangle Park, NC

Sep 82

U.S. Department of Commerce
National Technical Information Service
NTIS

Repro master

DEN 81-203-001-12-24

#1302

EPA-600/2-82-070c
September 1982

PB83-101337

ACID RAIN MITIGATION STUDY

Volume III

Industrial Boilers and Processes

by

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EPA Contract No: 68-02-3171

Work Assignment 12

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Prepared for:

INDUSTRIAL ENVIRONMENTAL RESEARCH LABORATORY
OFFICE OF RESEARCH AND DEVELOPMENT
U.S. ENVIRONMENTAL PROTECTION AGENCY
RESEARCH TRIANGLE PARK, NC 27711

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U.S. DEPARTMENT OF COMMERCE
SPRINGFIELD, VA 22161

TECHNICAL REPORT DATA
(Please read Instructions on the reverse before completing)

1. REPORT NO.	2.	3. RECIPIENT'S ACCESSION NO.
EPA-600/2-82-070c		PB83 101337

4. TITLE AND SUBTITLE	5. REPORT DATE
Acid Rain Mitigation Study: Volume III. Industrial Boilers and Processes	September 1982
	6. PERFORMING ORGANIZATION CODE
7. AUTHOR(S)	8. PERFORMING ORGANIZATION REPORT NO.
J. G. Ball, C. A. Muela, and J. L. Meling	DCN 81-203-001-12-24
9. PERFORMING ORGANIZATION NAME AND ADDRESS	10. PROGRAM ELEMENT NO.
Radian Corporation 8501 Mo-Pac Boulevard Austin, Texas 78766	11. CONTRACT/GRANT NO. 68-02-3171, Task 12
12. SPONSORING AGENCY NAME AND ADDRESS	13. TYPE OF REPORT AND PERIOD COVERED
EPA, Office of Research and Development Industrial Environmental Research Laboratory Research Triangle Park, NC 27711	Task Final; 2/80-2/81 14. SPONSORING AGENCY CODE EPA/600/13

15. SUPPLEMENTARY NOTES IERL-RTP project officer William D. Baasel is no longer with EPA. For details, contact P. P. Turner, Mail Drop 62, 919/541-2826. Volumes I and II concern FGD cost estimates.

16. ABSTRACT The report gives results of a 4-month study of existing industrial sources of SO2 emissions in the Acid Rain Mitigation Study (ARMS) region, including all the states east of the Mississippi River, as well as MN, IA, MO, AR, LA, ND, SD, NE, KS, OK, and TX. Study aims were to: (1) identify and characterize existing industrial sources of SO2 emissions, (2) identify control techniques that can be used to reduce SO2 emissions from these sources, and (3) estimate the SO2 emission reduction potential and the associated costs in constant 1980 dollars based on application of these controls. Simplifying assumptions were made for the balance of the SO2 sources studied. In addition, since sites were not visited, the remaining useful lives of the sources were not determined, and average FGD unit retrofit factors were estimated. Recommendations concerning the use of study results are discussed.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
Pollution	Pollution Control	13B
Sulfur Dioxide	Stationary Sources	07B
Boilers	Acid Rain	13A
Industrial Processes		13H
Rain		04B
Acidity		07D

18. DISTRIBUTION STATEMENT	19. SECURITY CLASS (This Report)	21. NO. OF PAGES
Release to Public	Unclassified	90
	20. SECURITY CLASS (This page)	22. PRICE
	Unclassified	

EPA Form 2220-1 (9-73)

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ABSTRACT

The U.S. Environmental Protection Agency has initiated a multi-phased study of the acid rain problem. As part of Phase I, Radian Corporation investigated SO_2 emissions and controls in the industrial sector.

The scope of this four-month study was limited to existing industrial sources of SO_2 emissions in the Acid Rain Mitigation Study (ARMS) region. This region includes all of the states east of the Mississippi River, as well as Minnesota, Iowa, Missouri, Arkansas, Louisiana, North Dakota, South Dakota, Nebraska, Kansas, Oklahoma, and Texas. The objectives of the study were to (1) identify and characterize existing industrial sources of SO_2 emissions, (2) identify the control techniques that can be used to reduce SO_2 emissions from these sources, and (3) estimate the SO_2 emission reduction potential and the associated costs in constant 1980 dollars based on application of these controls. Because of severe time limitations, only a portion of the SO_2 sources were investigated in detail. Simplifying assumptions were made about the balance of the SO_2 sources studied. Time constraints also prevented an evaluation of the availability of low sulfur control options (i.e., physically cleaned coal and low sulfur fuel oil). In addition since site visits were not made, the remaining useful lives of the sources were not determined and "average" flue gas desulfurization unit retrofit factors were estimated. Each of these considerations significantly affects both the potential SO_2 emissions reduction and the associated costs.

The results of the investigations conducted to meet each study objective are presented in this report. Recommendations concerning the use of these results are also discussed.

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ABBREVIATIONS AND ACRONYMS

ARMS	---	Acid Rain Mitigation Study
bbl	---	barrel
BPD	---	Barrels per day
EPRI	---	Electric Power Research Institute
FGD	---	Flue gas desulfurization
GCA	---	GCA Technology Division
HDS	---	Hydrodesulfurization
MAP3S	---	Multistate Atmospheric Power Production Pollution Study
MW_t	---	Megawatt thermal input
O&M	---	Operating and maintenance
NADB	---	National Air Data Branch
NEDS	---	National Emissions Data System
ROM	---	Run-of-mine
SIC	---	Standard Industrial Classification
SURE	---	Sulfate Regional Experiment
TPY	---	Tons per year

SECTION 1

INTRODUCTION

There is a growing concern about the acidity of precipitation in the northeastern United States and Canada. Acidic precipitation is thought by many scientists to kill aquatic and plant life, damage crop-growing soil, and accelerate erosion and damage to buildings. Although the mechanisms producing acid rain are not clearly understood, sulfur dioxide (SO_2) and oxides of nitrogen (NO_x) are thought to be the precursors of the chemicals that cause acid rain. Large quantities of SO_2 and NO_x are produced by various combustion and non-combustion processes in both the utility and industrial sectors.[1] Reducing these SO_2 and NO_x emissions to the atmosphere should reduce the potential for acid rain.

Because of this growing concern, the United States Environmental Protection Agency (EPA) initiated a multi-phased study of the acid rain problem. As part of this study, Radian Corporation investigated SO_2 emissions and controls in the industrial sector, while Teknekron, Inc. made a similar study of the utility sector. The study was to be completed in four months to provide direction for additional phases. These later phases were planned to investigate SO_2 emissions in more detail than Phase I, to investigate NO_x sources, and to model source/receptor relationships.

The scope of this study was limited to existing industrial sources of SO_2 emissions in the Acid Rain Mitigation Study (ARMS) region. This region includes all of the states east of the Mississippi River, as well as Minnesota, Iowa, Missouri, Arkansas, Louisiana, North Dakota, South Dakota, Nebraska, Kansas, Oklahoma, and Texas. The objectives of the study were to (1) identify and characterize existing industrial sources of SO_2 emissions, (2) identify

the control techniques that can be used to reduce SO_2 emissions from these sources, and (3) estimate the SO_2 emission reduction potential and the associated costs* based on application of these controls. Because of severe time limitations, only a portion of the SO_2 sources were investigated in detail. Simplifying assumptions were made about the balance of the SO_2 sources studied.

It should also be noted that, due to time constraints, the availability of low sulfur control options (i.e., physically cleaned coal and low sulfur fuel oil) was not evaluated. In addition since site visits were not made, the remaining useful lives of the sources were not determined and "average" flue gas desulfurization unit retrofit factors were estimated. Each of these considerations significantly affects both the potential SO_2 emissions reduction and the associated costs.

This report is divided into four major sections. Section 2 is a summary of the study. Section 3 describes the SO_2 emissions data base, followed by a characterization of SO_2 emissions in the industrial sector. Section 4 describes the environmental control systems that are considered applicable for reducing SO_2 emissions in the industrial sector. The SO_2 emissions reduction potential and the capital investment and annual costs resulting from applying the SO_2 control systems are estimated and discussed in Section 5. The Appendices show example calculations and give detailed data supporting the summary tables in the text.

*All of the costs presented in this study are expressed in constant 1980 dollars.

SECTION 2

SUMMARY

The objectives of the study were to: (1) identify and characterize the existing industrial sources of SO_2 emissions within the Acid Rain Mitigation Study (ARMS) region, (2) identify the control techniques that can be used to reduce these SO_2 emissions, and (3) estimate the SO_2 emission reduction potential and associated costs based on application of these controls to the industrial SO_2 sources. This section summarizes the study results for each of these objectives. In addition, the assumptions made and recommendations concerning the use of these results are also discussed.

2.1 SO_2 EMISSIONS CHARACTERIZATION

The Multistate Atmospheric Power Production Pollution Study (MAP3S) was used as a basis for a survey of industrial plants emitting SO_2 within the Acid Rain Mitigation Study (ARMS) region. This survey identified 257 major industrial emitters (an emitter may contain more than one point source) of SO_2 ranging in magnitude of SO_2 emissions from 5,000 to 200,000 tons per year. These data show that utility and industrial plants emitting more than 5,000 tons per year of SO_2 account for 90% of the total SO_2 emissions. Because of time limitations in this initial phase, plants with 5,000 tons per year of SO_2 emissions were the smallest emitters evaluated in this study.

The total quantity of SO_2 emitted each year by these 257 industrial plants is 3.6 million tons. Thirty-nine industrial plants, each emitting more than 20,000 tons of SO_2 per year, together account for about 1.6 million tons of this total. Only these 39 plants were studied in individual detail.

For these 39 plants, industrial boilers are responsible for 695.3 thousand tons of SO_2 per year. Non-boiler processes in the metals industry emit about 543.2 thousand tons of SO_2 per year; and in other industries, including chemicals, petroleum refining, and cement, non-boiler sources contribute some 350.0 thousand tons of SO_2 per year. These data are summarized in Table 2-1.

Due to time and feasibility constraints, SO_2 emissions from plants emitting between 5,000 and 20,000 tons per year were not characterized individually. They were evaluated by making a number of assumptions which are summarized as follows: (1) the approximately 2 million tons of SO_2 per year emitted by the 218 plants emitting between 5,000 and 20,000 per year were assumed to result exclusively from coal-, oil-, and gas-fired boilers, (2) the distribution of SO_2 emissions between coal-, oil-, and gas-fired boilers was assumed to be the same as that of the boilers in plants emitting more than 20,000 tons per year of SO_2, (3) the size distribution of these boilers was assumed to be similar to the nationwide distribution of industrial watertube boilers, and (4) the percent sulfur in coal, oil, and gas was assumed to be the same as the fuel-weighted average sulfur content of the boilers in plants emitting more than 20,000 tons per year of SO_2. The results of these calculations are presented in Table 2-2.

2.2 APPLICABLE SO_2 EMISSION CONTROL TECHNOLOGIES

Both pre- and post-combustion cleaning processes have been used to reduce SO_2 emissions from industrial combustors. The pre-combustion processes most commonly used for coal- and oil-fired combustors are physical coal cleaning and oil desulfurization, respectively. Another method of reducing SO_2 emissions from industrial boilers is to substitute naturally-occurring low sulfur coal and oil for high sulfur fuels. The most commonly used post-combustion process is flue gas desulfurization (FGD). In the metals and process industries, SO_2 emissions from non-combustion sources have also been controlled by FGD processes. In addition, sulfuric acid plants are frequently used to recover the SO_2 if the flue gas is sufficiently concentrated to warrant economic recovery.

TABLE 2-1. INDUSTRIAL SO_2 EMISSIONS FROM 39 LARGEST SO_2 EMITTERS

Process	Emissions* (10^3 Ton SO_2 Per Year) Per Process	Total	Percent of Total
Boilers		695.3	43.1
Coal-fired (>100 MW_t)	(392.4)		
Coal-fired (<100 MW_t)	(86.9)		
Oil-fired	(172.6)		
Gas-fired	(43.4)		
Metals Industry (excluding boilers)		543.2	33.7
Copper smelting	(235.9)		
Iron and steel	(115.3)		
Coke metallurgy	(99.2)		
Lead smelting	(85.4)		
Aluminum	(3.1)		
Other	(4.3)		
Other Industrial Processes (excluding boilers)		350.0	21.7
Cat crackers	(71.3)		
Process heaters	(60.3)		
Cement kilns	(54.2)		
Sulfuric acid	(49.7)		
Phosphate fertilizer	(41.8)		
Sulfur plants	(33.9)		
Alfalfa dehydration	(21.6)		
Flares	(8.9)		
Sulfite pulping	(7.0)		
Sludge conversion	(1.3)		
Unclassified		25.5	1.5
		1614.0	100.0

* Based on 1977 survey.

TABLE 2-2. SIZE DISTRIBUTION OF BOILERS NEEDED TO ACCOUNT FOR TWO MILLION[a] TONS OF SO_2 EMITTED PER YEAR FROM PLANTS EMITTING BETWEEN 5,000 and 20,000 TONS/YEAR OF SO_2

Average Boiler Size (MW_t)	COAL			OIL			GAS		
	10^3 Tons SO_2/Yr	10^3 Tons SO_2/ Yr/Boiler	Approximate Number of Boilers[b]	10^3 Tons SO_2/Yr	10^3 Tons SO_2/ Yr/Boiler	Approximate Number of Boilers[b]	10^3 Tons SO_2/Yr	10^3 Tons SO_2/ Yr/Boiler	Approximate Number of Boilers[b]
45	686	1.6	429	290	1.1	264	51	0.6	85
96	371	3.4	109	135	2.3	59	22	1.3	17
220	172	7.8	22	56	5.4	10	17	2.9	6
700 (coal, oil)	149	24.9	6	15	17.1	1	-	-	-
1265 (gas)	-	-	-	-	-	-	36	16.9	2
Total.	1378		566	496		334	126		110

Average Boiler Size (MW_t)	TOTAL	
	Approximate Number of Boilers[b]	10^3 Tons SO_2/Yr
45	778	1027
96	185	528
220	38	245
700 (coal, oil)	7	164
1265 (gas)	2	36
Total	1010	2000

[a] The actual total of 1996 x 10^3 tons per year was rounded to 2000 x 10^3 tons per year.

[b] The number of boilers in each size category that would yield the annual SO_2 emissions derived in Table 3-8 given the fuel quality and average boiler size and capacity factor discussed in the text.

al total of 1996 x 10^3 tons per year was rounded to 2000 x 10^3 tons per year.

2.3 ESTIMATED COSTS OF APPLYING SO_2 CONTROL TECHNIQUES TO INDUSTRIAL SOURCES AND THE POTENTIAL SO_2 EMISSIONS REDUCTIONS

Preliminary costs* for reducing SO_2 emissions from different industrial sources with the control alternatives identified above were developed in this section. Because each control alternative cannot be effectively applied to all of the industrial sources, the control alternatives were applied only to those source categories that seem to be logical based on actual installations. Only one scenario was evaluated.

The use of physically cleaned coal to reduce SO_2 emissions was applied to boilers having capacities less than 75 MW_t (boiler heat input in thermal megawatts**), and firing coals with 2.0 percent or greater sulfur content. This control method was adopted for small coal-fired boilers because an FGD process would require very high capital investment/annual costs. The use of physically cleaned coal would reduce uncontrolled SO_2 emissions from these boilers by 219 x 10^3 tons per year, which represents about a 30 percent reduction. It was assumed that physically cleaned coal would be purchased from a major coal producer. As a result, each boiler operator would not incur the costs of constructing and operating a physical coal cleaning facility; instead, the operator would pay the producer a premium for cleaning the coal. The cost for physically cleaned coal was estimated to be $4.28 per ton (1980 dollars) for a total annual premium of approximately $46 x 10^6 dollars for the applicable industrial sources. This cost represents the cost of preparation and does not include the costs of raw coal, taxes, and transportation. The availability of physically cleaned coal to the SO_2 sources was not examined.

*The capital investment and annual costs are significant only to two figures; however, results are reported to the last whole significant figure to be consistent with other similar studies. In this study, annual costs are first year costs and include O&M, overhead, utilities, etc., and capital-related charges equivalent to 0.13 times the total capital investment. All of the costs presented in this report are expressed in constant 1980 dollars.

**A boiler with a heat input capacity of 200 x 10^6 Btu/hr would have a capacity of 58.6 MW_t.

Low sulfur fuel oil was assumed to be used for reducing emissions from all oil-fired boilers. Uncontrolled SO_2 emissions from these boilers are approximately 669 x 10^3 tons per year. The use of low sulfur fuel oil (0.8% S) reduced the uncontrolled emissions by 51 percent assuming an average uncontrolled fuel oil sulfur content of 1.64 percent. It was assumed that low sulfur oil would be purchased from a major producer. The resulting incremental cost for the low sulfur oil was taken as $2.50/bbl (based on hydrodesulfurization costs) for a total annual premium of $314 x 10^6. This represents the incremental cost of the lower sulfur fuel compared to the fuel currently being used. The availability of low sulfur oil to the SO_2 emission source was not examined.

FGD systems were assumed to be used for reducing emissions from all of the larger-sized coal-fired boilers (those having capacities greater than 75 MW_t). FGD would reduce SO_2 emissions from these boilers by approximately 940 x 10^3 tons per year. The capital investment cost for installing these FGD systems would be about $2,020 x 10^6.* The annual cost associated with these FGD systems would be approximately $565 x 10^6. The capital investment and annual costs for industrial FGD systems were derived by integrating cost studies for small industrial and large utility systems. This integration required putting the cost studies on the same equipment basis, using the same investment and cost algorithms, and using the same unit pricing of labor and raw materials.

FGD systems were also assumed to be used for most non-boiler sources in the metals and process industries for all processes emitting greater than 1000 tons per year of SO_2 from a single point source. Retrofitting an FGD process to the uncontrolled sources in the metals industry decreased SO_2 emissions from 543 x 10^3 tons per year to 62 x 10^3 tons per year. A capital investment of $420 x 10^6 and an annual cost of about $128 x 10^6 would be required to achieve this reduction. In the process industry, the use of FGD systems on process heaters, sludge concentrators, sulfuric acid plants, catalytic crackers, and elemental sulfur plants reduced SO_2 emissions from 350 x 10^3 to 64 x 10^3

*The capital investment for an FGD system retrofit was assumed to be 1.3 times the capital investment for an FGD system applied to a new boiler.

tons per year, an 82 percent reduction. The capital and annual costs required to achieve this reduction would be \$580 x 10^6 and \$178 x 10^6, respectively. A summary of the assumed SO_2 control applications is presented in Table 2-3. The costs used for FGD applications are illustrated in Figures 2-1 and 2-2.

Overall, the plants within the industrial sector emitting greater than 5,000 tons per year of SO_2 (257 plants) generate approximately 3.6 x 10^6 tons of SO_2 per year. Implementation of the control options described above would reduce the uncontrolled SO_2 emissions by approximately 63 percent. To achieve this reduction, industry within the ARMS region would have to invest about \$3.0 billion for installing the control processes, as well as incur annual costs of about \$1.2 billion (See Table 2.4). Plants emitting more than 20,000 tons per year of SO_2 (39 plants) account for 1.6 x 10^6 tons per year of uncontrolled SO_2 emissions. Marginal cost and investment analysis shows that investment and cost per ton of SO_2 removed is lower for these plants than for plants emitting 5,000 to 20,000 tons per year of SO_2 (see Tables 2-4 and 2-5). The controls applied to the 39 plants could reduce uncontrolled SO_2 emissions by 75 percent and would require a \$1.5 billion capital investment and about \$0.6 billion in annual costs.

The cost effectiveness (in \$ ton/SO_2 removed) for the various control options are summarized below:

Application	Boiler Size MW_t	Fuel/ Wt. % Sulfur	SO_2 Control Technology	\$/ton SO_2 removed for plants emitting more than: 5000 tons per year of SO_2	20,000 tons per year of SO_2
Boilers	<75	Coal/3%	Physical Coal Cleaning	210	210
Boilers	>75	Coal/2.4	FGD	601	558
Boilers	All	Fuel Oil/1.6	Low Sulfur oil*	915	910
Nonboiler sources/ Metals Industry	-	-	FGD	266	266
Nonboiler sources/ Process Industry	-	-	FGD	622	622
Weighted Average				542	472

* costs are based on hydrodesulfurization.

TABLE 2-3. SUMMARY OF SO_2 CONTROL APPLICATIONS

CONTROL APPLIED	SOURCE CATEGORY	TYPE OF FUEL USED	AVERAGE SULFUR LEVEL IN FUEL (%)[e]	BOILER SIZE (MW_t)	NUMBER OF AFFECTED BOILERS
None[a]	Boilers	Coal	1.3	All Sizes	31[f]
Physically Cleaned Coal	Boilers	Coal	3.0	<75	449[f]
FGD (Limestone)	Boilers	Coal	2.4	>75	193
Oil Desulfurization (0.8% S Oil)	Boilers	Oil	1.64	All Sizes	441
None	Boilers	Gas	0.8	All Sizes	160
FGD[d]	Non-boiler sources in metals industry	-	-	25-644[b]	-
FGD	Non-boiler sources in process industry	-	-	17-1000[c]	-

[a]Boilers in the top 39 SO_2-emitting plants currently firing 2.0% or lower sulfur coal do not require controls.

[b]The capacities of non-boiler sources in the metal industry are equivalent to boilers of this size range.

[c]The capacities of non-boiler sources in the process industry are equivalent to boilers of this size range.

[d]Sulfuric acid plants were used as controls on two smelting operations.

[e]Before controls are applied.

[f]Nine boilers were unclassified as to size and nine boilers were unclassified as to fuel type. Fourteen of these boilers were found to be at sites that uses low S coal exclusively. Thus the number of low S coal burning boilers was increased from 17 to 31. The other four unclassified size/fuel boilers were arbitrarily assigned to physically cleaned coal.

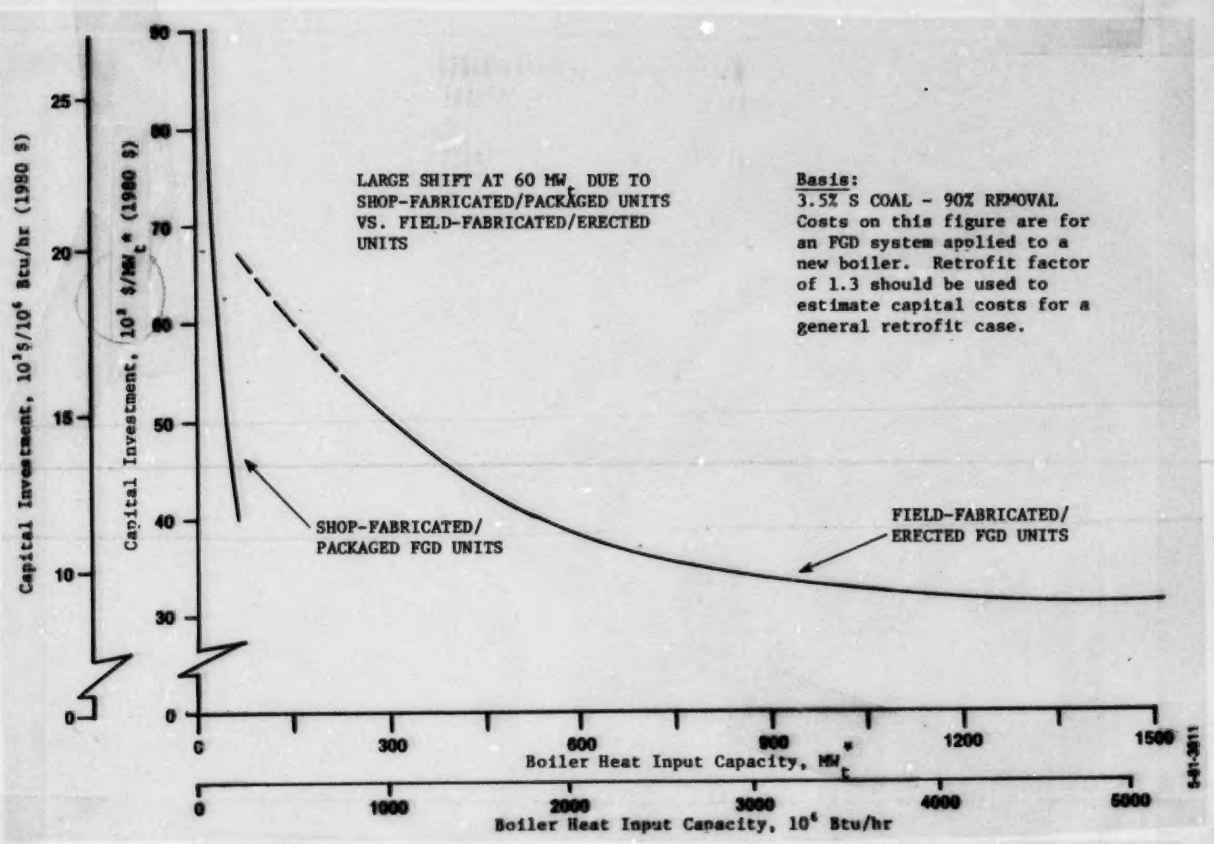
Capital Investment, 10^3/10^6 Btu/hr (1980 $)
Capital Investment, 10^3 $/MW_t* (1980 $)
LARGE SHIFT AT 60 MW DUE TO SHOP-FABRICATED/PACKAGED UNITS VS. FIELD-FABRICATED/ERECTED UNITS
Basis:
3.5% S COAL - 90% REMOVAL
Costs on this figure are for an FGD system applied to a new boiler. Retrofit factor of 1.3 should be used to estimate capital costs for a general retrofit case.
SHOP-FABRICATED/ PACKAGED FGD UNITS
FIELD-FABRICATED/ ERECTED FGD UNITS
Boiler Heat Input Capacity, MW_t*
Boiler Heat Input Capacity, 10^6 Btu/hr
5-81-3811

FIGURE 2-1. CAPITAL INVESTMENT FOR A LIMESTONE FGD SYSTEM (APPLIED TO A NEW BOILER)

*1 MW_t = 3.412 x 10^6 Btu/hr.

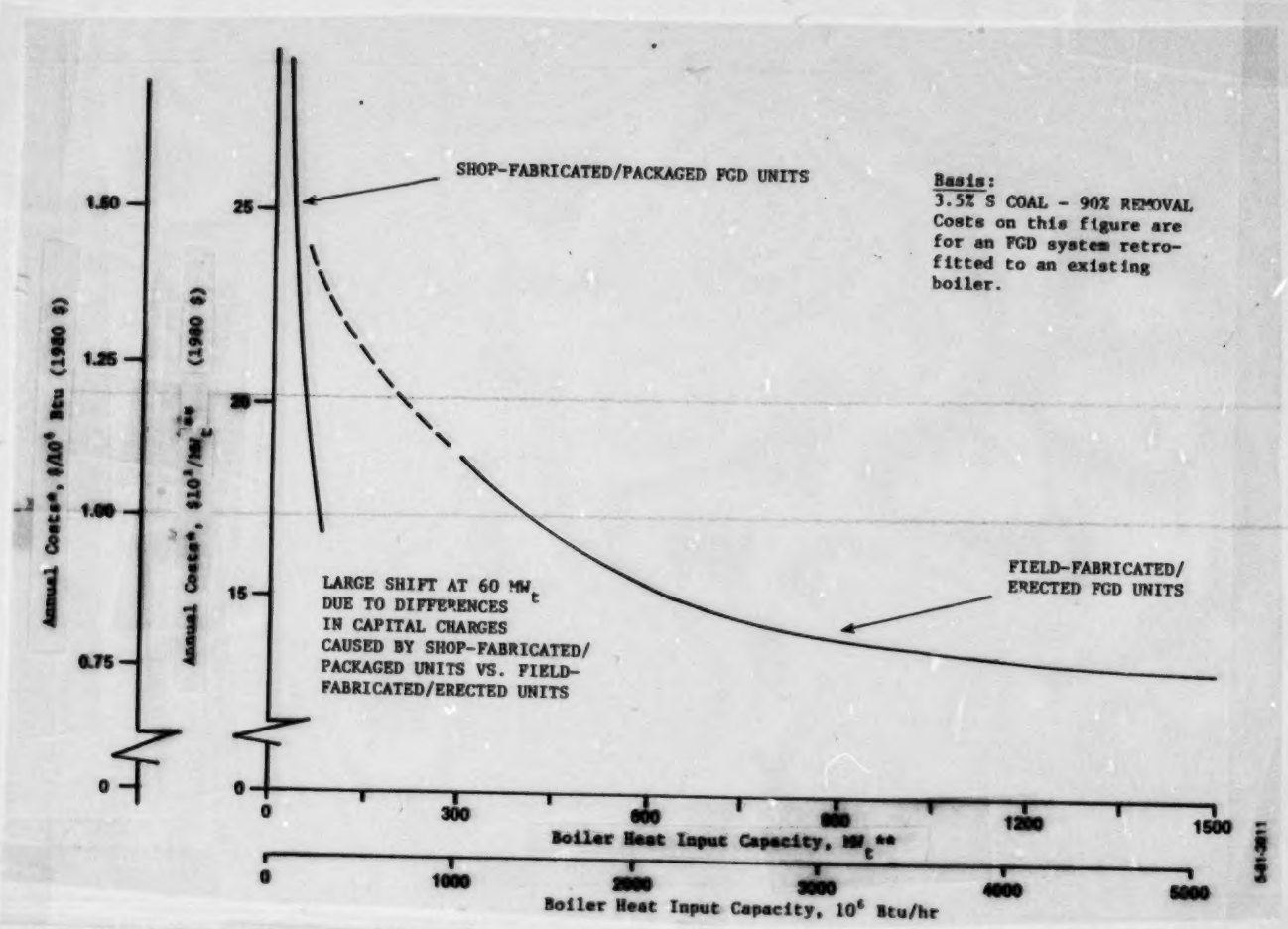

FIGURE 2-2. ANNUAL COSTS FOR A RETROFITTED LIMESTONE FGD SYSTEM

* Annual Costs are expressed two ways:

- $/10^6 Btu is the annual costs ($/year) divided by the annual boiler heat input (Btu's/year).
- $/MWt is the annual costs ($/year) divided by the boiler capacity (MWt).

** 1 MWt = 3.412 x 10^6 Btu/hr.

TABLE 2-4. SUMMARY OF IMPACT AND COST OF CONTROLS FOR PLANTS EMITTING MORE THAN 5,000 TONS/YEAR OF SO_2

SO_2 Emission Sources[f]					SO_2 Control Processes					
Source Category	Fuel Type	Boiler Size MW$_t$	Avg. Sulfur Level (%)	Uncontrolled SO_2 Emissions (10^3 Ton/Yr)	Control Applied	SO_2 Reduction Achieved (%)	Controlled SO_2 Emissions (10^3 Ton/Yr)	Capital Investment[g] ($10^6)	Annual Cost ($10^6)[e,g]	Cost Effectiveness[g] ($/Ton SO_2 Removed)
Boilers	Coal	-[c]	1.3	83	None	-	83	-	-	-
	Coal	<75	3.0	730	Physical Coal Cleaning	30	511	-	46[a]	210
	Coal	>75	2.41	1044	FGD (Limestone)	90	104	2,020	585	601
	Fuel Oil	All	1.64	669	Low sulfur fuel oil	51[b]	326	-	314[a]	915
	Gas	All	0.8	169	None	-	169	-	-	-
Non-Boiler Sources (Metals Industry)	-		-	543	FGD (Limestone)[d,h]	89	62	420	128	266
Non-Boiler Sources (Process Industry)	-		-	350	FGD (Limestone)[h]	82	64	580	178	622
TOTALS				3,588		63[f]	1,319	3,020	1,231	542[f]

[a] The cost directly represents the premium paid by boiler operator for upgraded fuel.

[b] This reduction efficiency is set by assuming the use of 0.8 percent sulfur fuel oil down from an average level of 1.64 percent. The costs are based on resid hydrodesulfurization.

[c] Boilers in the top 39 SO_2 emitters that actually burn <2.0 percent sulfur coal.

[d] Includes two sulfuric acid plants.

[e] In this report annual costs include annual O&M, overhead, utilities, etc., and annual capital-related charges equivalent to 0.13 times the total capital investment.

[f] Uncontrolled emissions for 1977.

[g] 1980 $.

[h] FGD process applied to point sources emitting greater than 1000 tons per year SO_2.

[f] Weighted average.

TABLE 2-5. SUMMARY OF IMPACT AND COSTS OF CONTROLS FOR PLANTS EMITTING MORE THAN 20,000 TONS/YEAR OF SO_2

Source Category	SO_2 Emissions Sources[f] Fuel Type	Boiler Size MW_t	Avg. Sulfur Level (%)	Uncontrolled SO_2 Emissions (10^3 Ton/Yr)	SO_2 Control Processes Control Applied	SO_2 Reduction Achieved (%)	Controlled SO_2 Emissions (10^3 Ton/Yr)	Capital Investment[g] (10^6)	Annual Cost (10^6)[e,g]	Cost Effectiveness[g] ($/Ton SO_2 Removed)
Boilers										
	Coal	-[c]	1.3	83	None	-	83	-	-	-
	Coal	<75	3.0	44	Physical Coal Cleaning	30	31	-	3[a]	210
	Coal	>75	2.41	352	FGD (Limestone)	90	35	471	170	536
	Fuel Oil	All	1.64	173	Low sulfur oil	51[b]	84	-	81[a]	910
	Gas		0.8	43	None	-	43	-	-	-
Non-boiler Sources (Metals Industry)	-		-	543	FGD (Limestone)[d,h]	89	62	420	128	366
Non-boiler Sources (Process Industry)	-		-	350	FGD (Limestone)[h]	82	64	580	178	622
Total				1,588		75[f]	402	1,471	560	472[f]

[a] The cost directly represents the premium paid by boiler operator for upgraded fuel.

[b] This reduction efficiency is set by assuming the use of 0.8 percent sulfur fuel oil down from an average level of 1.64 percent. The costs are based on resid hydrodesulfurization.

[c] Boilers in the top 39 SO_2 emitters that actually burn <2.0 percent sulfur coal.

[d] Includes two sulfuric acid plants.

[e] In this report annual costs include annual O&M, overhead, utilities, etc., and annual capital-related charges equivalent to 0.13 times the total capital investment.

[f] Uncontrolled emissions for 1977.

[g] 1980 $.

[h] FGD processes applied to point sources emitting greater than 1000 tons per year SO_2.

[i] Weighted average.

The average cost effectiveness for the controls evaluated range from about $210/ton of SO_2 for physical coal cleaning to $915/ton for oil hydrodesulfurization.

2.4 RECOMMENDED USE OF STUDY RESULTS

Preliminary estimates of the SO_2 reduction potential from existing industrial sources and the associated control costs are provided in this study and will be useful for planning future work in the acid rain area. Due to time and budget constraints, a number of key assumptions have been made in order to obtain these results. Many of these assumptions have been highlighted in this summary.

If control of existing industrial sources of SO_2 is considered to be a reasonable strategy for attacking the acid rain problem, then a more detailed evaluation of the industrial sector should be undertaken. The scope of work should include:

1. A more detailed characterization of the targeted point sources. Site visits should be made.

2. An evaluation of the availability and costs of low sulfur fuel oil, low sulfur coal, and physically cleaned coal to the various plants.

3. A characterization of source ages and remaining useful lives.

4. Engineering evaluations to assess the feasibility and cost of FGD retrofits.

5. An evaluation of other scenarios for controlling SO_2 emissions.

SECTION 3

CHARACTERIZATION OF INDUSTRIAL SECTOR SO_2 EMISSION SOURCES IN THE ARMS REGION

Although industrial sector emissions of SO_2 are approximately 15% of those from the utility sector, their impacts are potentially serious enough to warrant a detailed characterization of industrial sources. To study these emission sources, data were acquired from Brookhaven National Laboratory (BNL). These data were part of an EPA project, The Multistate Atmospheric Power Production Pollution Study, which is discussed briefly in Section 3.1. The characterization of industrial SO_2 emission sources developed from these data is presented in Section 3.2.

3.1 THE MAP3S DATA BASE

The Multistate Atmospheric Power Production Pollution Study (MAP3S) is an EPA-directed project charged with assessing air quality impacts in the northeastern region of the United States. Researchers from a number of government labs and several universities are involved. A portion of the work on this program has entailed compiling a comprehensive emissions inventory. The emissions inventory includes major emitters of criteria pollutants and covers both power and nonpower sources of emissions.

Initial emissions data were acquired by Brookhaven National Laboratory in early 1976. These data were taken from EPA's National Emissions Data System (NEDS) and covered the northeastern United States. The current MAP3S data base contains information extracted from NEDS in late 1977. At that time, data for the whole United States were obtained, and the data of primary interest (i.e., for the eastern half of the U.S.) were examined. Validation cross-checks were performed on the reported state,

county, latitude, and longitude for sources emitting more than 5×10^6 Kgs of SO_2 per year. Corrections were made by BNL where necessary.

At the same time that the locational corrections were being made at BNL, corrections to emissions and fuel usage data were being made by GCA Technology Division, Bedford, Massachusetts, in conjunction with the Electric Power Research Institute's Sulfate Regional Experiment (SURE) program. GCA was chosen by EPRI to develop the SURE emissions inventory, starting with the same basic NEDS data used by BNL. BNL and GCA exchanged correction data, and the GCA corrections were incorporated into the MAP3S inventory. Because of these corrections, the MAP3S and SURE are considered to be the two best large-scale emission inventories.

The MAP3S point source emission inventory has been organized by grouping information by state, county, plant, and point. ("Plant" refers to an overall facility at one location; "point" means a single stack or other emission point within a plant.) For each plant, general information such as plant name, owner, Standard Industrial Classification (SIC) code, and NEDS identification number is listed. Most information, however, is listed at the "point" level. Included is information on type of emission point (process or boiler), emission levels, emission control devices (if any), stack parameters, operating schedule, compliance status, fuel type and characteristics, and boiler size (if applicable).

When dealing with a data base as large as the MAP3S emission inventory, questions of quality are certain to arise. To better understand why this is so, a brief review of the original source, namely NEDS, is necessary.

Basically, NEDS, which is under the auspices of EPA's National Air Data Branch (NADB), was set up to be the national emissions inventory, incorporating data supplied by the states under their State Implementation Plans. All plants emitting total criteria pollutants in amounts exceeding

100 tons per year were to be included. In theory, the result should be a comprehensive, up-to-date inventory of major emitters. However, certain intervening factors have caused the quality of NEDS data to be less than intended.

First, individual states are responsible for two vital steps needed in the formation of the emissions data base: the acquisition of the data, and its submittal to NADB. Acquisition of data requires initiating a statewide emission inventory which, in turn, requires individual plants to supply the necessary information. Submittal of data implies coding it into the proper NEDS format and sending it to NADB. Problems can arise at either step. According to the NADB, some states simply do not have the manpower, money, or computer facilities to perform extensive emission inventories on a regular basis, or to code the data into the proper format.[2]

Second, data input to NEDS originates at the plant level. Since some plants are more conscientious than others about the quality and quantity of emissions information supplied, it is at this level that the quality of NEDS is established.

Furthermore, any data base originating with NEDS, such as the MAP3S emission inventory, is subject to the same quality considerations as NEDS. Some data are quite old (1970) and have not been updated, and some errors were found during this study. Several specific cases illustrate this fact. A number of the largest SO_2 emitters in the acid rain study area were checked by phone contacts. A Getty Oil refinery in Delaware was reported in the MAP3S inventory to emit 101,200 tons of SO_2 per year. Sources at the plant indicated that the correct figure is now about 37,000 tons per year. An asphalt plant in Mississippi was reported to emit 61,000 tons of SO_2 per year. A phone check revealed that the size of the plant eliminated the possibility of SO_2 emissions of that magnitude. (This particular plant, producing 250,000 tons of asphalt per year, would have the potential to emit only about 6,000 tons of SO_2 per year, according to calculations based on

"Compilation of Air Pollutant Emission Factors," AP-42.) Three smelting operations, two in Texas and one in Oklahoma, with total reported SO_2 emissions of 167,300 tons per year, have been shut down. (For states west of the Mississippi River, corrections to the NEDS data were not attempted as part of either the MAP3S or SURE programs.)

In conclusion, then, the MAP3S emission inventory is not perfect. Its origin (NEDS) precludes this. However, its accuracy should be sufficient to insure a reasonable overall representation of the major industrial SO_2 emitters in the geographical area under consideration.

3.2 CHARACTERIZATION OF UNCONTROLLED SO_2 EMISSIONS FROM THE INDUSTRIAL SECTOR

3.2.1 Industrial Plants Emitting 5,000 Tons of SO_2 Per Year or More

Radian acquired the MAP3S emission inventory from Brookhaven National Laboratory to study industrial sector SO_2 emissions. (Teknekron Research, Inc. was, at the same time, studying utility sector SO_2 emissions.) The first objective was to determine an industrial plant-size cut-off point below which SO_2 emissions would not be characterized. Information supplied by Carmen M. Benkovitz, who is responsible for maintaining the MAP3S data base at BNL, revealed that the 480 largest SO_2-emitting plants east of the Mississippi River (including utilities) contribute 90.47 percent, or 19,357,863 tons, of the annual SO_2 emissions documented in the MAP3S inventory. Examining these plants in order of decreasing SO_2 emissions showed that the 480th plant emitted approximately 5,000 tons of SO_2 per year. This number was selected as the cut-off point. Data for the 480 largest SO_2 emitters are summarized in Table 3-1.

TABLE 3-1. SUMMARY OF THE 480 LARGEST INDUSTRIAL AND UTILITY SO_2 EMITTERS EAST OF THE MISSISSIPPI RIVER *

	Number of Plants	SO_2 Emissions (tons/yr)
Industrial sector	186	2.49×10^6
Utility sector	294	16.87×10^6
Total	480	19.36×10^6

*From 1977 Survey

While it is probably true that the industrial sector would contribute significantly to the remaining 9.53 percent of the SO_2 emissions, it is also true that the benefits derived at this time from characterizing these emissions would be very minor in relation to the amount of effort expended. To include 100 percent of the industrial sector emissions would mean examining more than 5,000 additional plants. The 5,000 tons per year cut-off point was, therefore, considered to be reasonable for the Phase I study.

After the cut-off point was selected, NEDS data for industrial sources emitting at least 5,000 tons of SO_2 per year in the ARMS region west of the Mississippi River were obtained from BNL. This increased the number of industrial sources to be studied from 186 to 257. Table 3-2 summarizes the industrial plants emitting at least 5,000 tons SO_2 per year by state and general Standard Industrial Classification (SIC) code.

3.2.2 Industrial Plants Emitting 20,000 Tons of SO_2 Per Year or More

After determining the initial plant-size cut-off point of 5,000 tons of SO_2 per year, it became apparent that characterizing the emissions from each of the 257 plants would be prohibitively time-consuming. Figure 3-1 was used to select a secondary break point of 20,000 tons of SO_2 per year, above which each plant's emissions would be characterized individually and below which they would be characterized by more general means (see

TABLE 3-2. PLANTS EMITTING MORE THAN 5,000 TONS OF SO_2 PER YEAR**

State	Total Number of Plants	Total SO_2 Emissions (tons/yr)	BY SIC* CODE			
			SIC Code	Description	Number	SO_2 Emissions (tons/yr)
Alabama	2	31,061	28XX	Chemicals	2	31,061
Arkansas	None	0				
Connecticut	None	0				
Delaware	4	68,057	28XX	Chemicals	3	31,057
			29XX	Petroleum Refining	1	37,000
D.C.	None	0				
Florida	15	213,651	20XX	Food Products	1	82,839
			26XX	Paper Products	4	35,866
			28XX	Chemicals	4	44,169
			29XX	Petroleum Refining	2	19,152
			32XX	Concrete Products	4	31,625
Georgia	5	42,285	26XX	Paper Products	4	37,066
			32XX	Concrete Products	1	5,219

*Standard Industrial Classification

**From 1977 Survey

(Continued)

TABLE 3-2 (Continued)

State	Total Number of Plants	Total SO_2 Emissions (tons/yr)	BY SIC* CODE			
			SIC Code	Description	Number	SO_2 Emissions (tons/yr)
Illinois	18	212,735	20XX	Food Products	3	39,152
			26XX	Paper Products	1	13,064
			28XX	Chemicals	4	49,485
			29XX	Petroleum Refining	6	83,826
			33XX	Primary Metals	2	14,796
			35XX	Machinery	1	6,718
			Other		1	5,694
Indiana	11	279,280	29XX	Petroleum Refining	2	72,248
			32XX	Concrete Products	1	5,136
			33XX	Primary Metals	6	185,910
			37XX	Transportation Equipment	1	9,486
			Other		1	6,500
Iowa	7	96,485	20XX	Food Products	2	51,139
			28XX	Chemicals	1	6,807
			32XX	Concrete Products	4	38,539
Kansas	None	0				

(Continued)

TABLE 3-2 (Continued)

State	Total Number of Plants	Total SO_2 Emissions (tons/yr)	BY SIC* CODE			
			SIC Code	Description	Number	SO_2 Emissions (tons/yr)
Kentucky	4	52,990	28XX	Chemicals	2	25,226
			29XX	Petroleum Refining	1	19,676
			36XX	Electrical Equipment	1	8,088
Louisiana	9	98,495	26XX	Paper Products	1	5,567
			28XX	Chemicals	2	13,385
			29XX	Petroleum Refining	6	79,543
Maine	7	55,021	26XX	Paper Products	1	55,021
Maryland	4	66,727	26XX	Paper Products	1	26,509
			28XX	Chemicals	1	5,777
			32XX	Concrete Products	1	7,229
			33XX	Primary Metals	1	27,212
Massachusetts	1	5,631	35XX	Machinery	1	5,631
Michigan	5	149,596	10XX	Metal Mining	1	77,193
			28XX	Chemicals	2	38,420
			32XX	Concrete Products	2	33,983

(Continued)

TABLE 3-2 (Continued)

State	Total Number of Plants	Total SO_2 Emissions (tons/yr)	BY SIC* CODE			
			SIC Code	Description	Number	SO_2 Emissions (tons/yr)
Minnesota	1	19,654	29XX	Petroleum Refining	1	19,654
Mississippi	6	45,916	26XX	Paper Products	3	18,455
			28XX	Chemicals	1	10,376
			29XX	Petroleum Refining	1	7,550
			Other		1	9,535
Missouri	8	151,838	28XX	Chemicals	3	23,923
			29XX	Petroleum Refining	1	15,840
			32XX	Concrete Products	3	54,375
			33XX	Primary Metals	1	47,700
Nebraska	None	0				
New Hampshire	1	5,880	26XX	Paper Products	1	5,880
New Jersey	3	37,999	26XX	Paper Products	1	21,885
			28XX	Chemicals	1	8,386
			29XX	Petroleum Refining	1	7,728

(Continued)

TABLE 3-2 (Continued)

State	Total Number of Plants	Total SO_2 Emissions (tons/yr)	BY SIC* CODE			
			SIC Code	Description	Number	SO_2 Emissions (tons/yr)
New York	3	42,774	32XX	Concrete Products	2	28,981
			33XX	Primary Metals	1	13,793
North Carolina	8	70,967	22XX	Textiles	1	8,062
			26XX	Paper Products	4	36,566
			28XX	Chemicals	2	21,217
			32XX	Concrete Products	1	5,122
North Dakota	1	8,071	29XX	Petroleum Refining	1	8,071
Ohio	28	408,589	20XX	Food Products	1	8,667
			26XX	Paper Products	1	44,735
			28XX	Chemicals	4	99,429
			29XX	Petroleum Refining	4	42,251
			30XX	Rubber Products	3	40,140
			32XX	Concrete Products	2	11,552
			33XX	Primary Metals	10	135,792
			35XX	Machinery	1	9,045
			37XX	Transportation Equipment	1	8,878
			Other		1	8,100

(Continued)

TABLE 3-2 (Continued)

State	Total Number of Plants	Total SO_2 Emissions (tons/yr)	BY SIC* CODE			
			SIC Code	Description	Number	SO_2 Emissions (tons/yr)
Oklahoma	5	39,194	29XX	Petroleum Refining	4	33,409
			33XX	Primary Metals	1	5,785
Pennsylvania	19	304,741	22XX	Textiles	1	7,657
			26XX	Paper Products	6	57,579
			28XX	Chemicals	1	9,609
			29XX	Petroleum Refining	4	37,189
			30XX	Rubber Products	1	21,770
			32XX	Concrete Products	1	6,346
			33XX	Primary Metals	4	147,316
			37XX	Transportation Equipment	1	17,275
Rhode Island	None	0				
South Carolina	3	38,943	26XX	Paper Products	2	25,973
			Other		1	12,970
South Dakota	None	0				

(Continued)

TABLE 3-2 (Continued)

State	Total Number of Plants	Total SO_2 Emissions (tons/yr)	BY SIC* CODE			
			SIC Code	Description	Number	SO_2 Emissions (tons/yr)
Tennessee	10	91,224	26XX	Paper Products	1	6,442
			28XX	Chemicals	6	68,402
			29XX	Petroleum Refining	1	5,594
			33XX	Primary Metals	1	5,064
			Other		1	5,722
Texas	40	703,576	13XX	Oil, Gas Extraction	13	102,899
			28XX	Chemicals	9	131,618
			29XX	Petroleum Refining	14	208,061
			32XX	Concrete Products	1	6,500
			33XX	Primary Metals	3	254,498
Vermont	None	0				
Virginia	13	103,702	26XX	Paper Products	4	32,738
			28XX	Chemicals	6	52,569
			29XX	Petroleum Refining	1	6,655
			Other		2	11,740

(Continued)

TABLE 3-2 (Continued)

State	Total Number of Plants	Total SO_2 Emissions (tons/yr)	BY SIC* CODE			
			SIC Code	Description	Number	SO_2 Emissions (tons/yr)
West Virginia	6	89,538	28XX	Chemicals	4	48,188
			33XX	Primary Metals	2	41,350
Wisconsin	10	75,677	26XX	Paper Products	10	75,677
TOTAL	257	3,610,297				

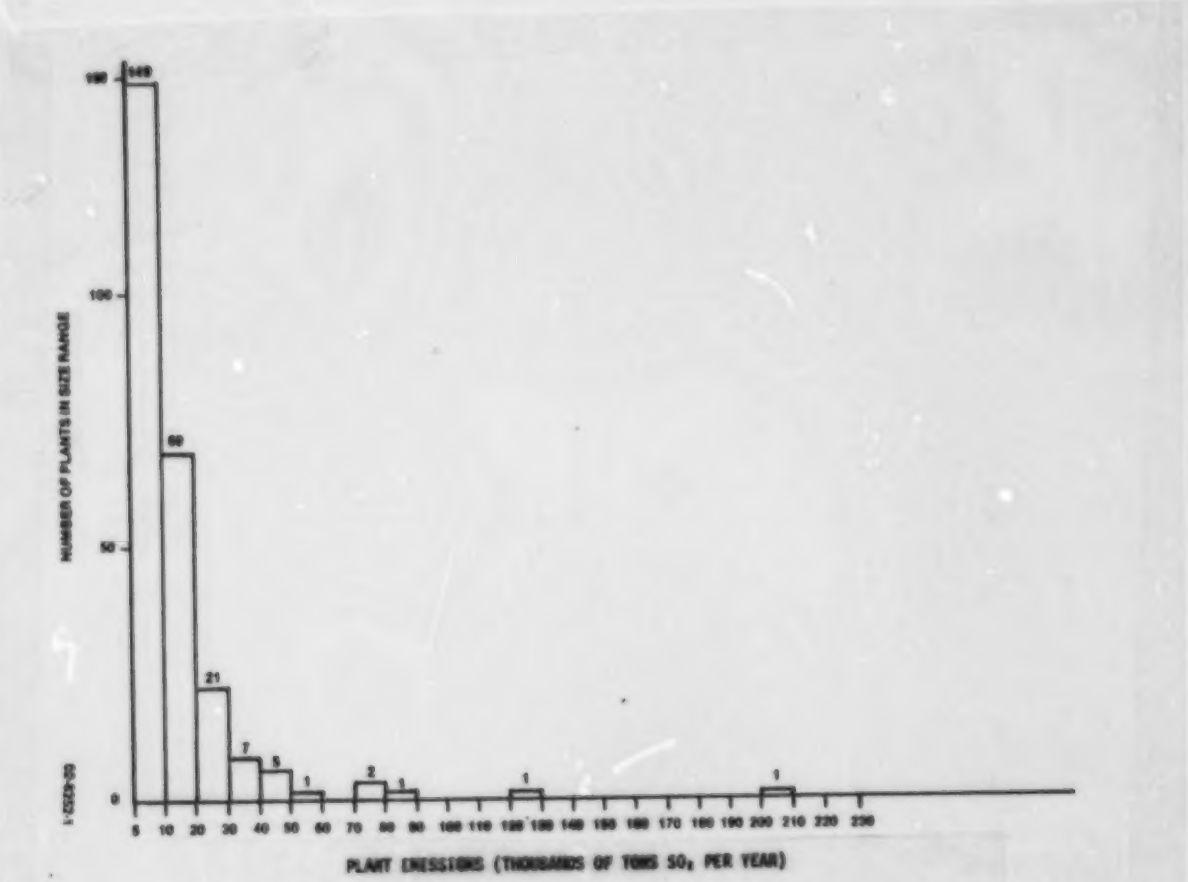

Figure 3-1. Distribution of 257 Industrial Plants by Tons of SO_2 Emitted (Based on 1977 Survey)

Section 3.2.3). As Figure 3-1 illustrates, 39 plants fit into the former category, 218 into the latter. Table 3-3 summarizes the 39 largest emitters in decreasing order of total plant SO_2 emissions. Table 3-4 presents by process type the SO_2 emissions from the largest 39 emitters.

The next step was to characterize the boilers included in the top 39 emitters. Table 3-5 shows the distribution of these industrial boilers by size and fuel type. SO_2 emissions from the 264 industrial boilers totaled 695.3 tons per year (TPY); of this total, coal-fired boilers contributed 479.3 TPY, and oil- and gas-fired boilers were responsible for 216.0 TPY. Sulfur levels in coal ranged from 0.8 to 4.4 percent, with a fuel-weighted average of 2.41 percent. Similarly, oil and process gas sulfur contents ranged from 0.6 to 5.0 percent and 0.15 to 1.7 percent, respectively, with fuel-weighted averages of 1.64 and 0.80 percent, respectively. Only process gas-fired boilers were reported and studied because natural gas-fired boilers do not emit significant amounts of SO_2.

3.2.3 Industrial Plants Emitting Between 5,000 and 20,000 Tons of SO_2 Per Year

Due to time and feasibility constraints, SO_2 emissions from plants emitting between 5,000 and 20,000 tons per year were not characterized individually. In addition, the mixture of industries in the 218 smaller plants was different than those in the 39 larger plants. Therefore, an extrapolation of the emission inventory information for the larger 39 plants to the smaller 218 plants was considered inappropriate. The 218 facilities were characterized by making a number of assumptions which will be discussed in this section. These assumptions are summarized as follows: (1) the approximately 2 million* tons of SO_2 per year emitted by the 218 plants emitting between 5,000 and 20,000 TPY were assumed to result exclusively from coal-, oil-, and gas-fired boilers; (2) the distribution of SO_2 emissions between coal-, oil-, and gas-fired boiers was assumed to be the same as that of boilers in plants emitting more than 20,000 TPY (see Section 3.2.2); (3) the size distribution of the boilers was assumed

*The actual total of 1996×10^3 tons per year was rounded to 2000×10^3 tons of SO_2 per year.

TABLE 3-3. INDUSTRIAL PLANTS EMITTING MORE THAN 20,000 TONS OF SO_2 PER YEAR[1]

Company	Plant Location	Plant SIC Code	Major SO_2 Emitting Processes	Total Plant SO_2 Emissions (Thousands of Tons Per Year)
ASARCO	TX	3331	Copper and lead smelting	200.9
US Steel	PA	3312	Boilers and coke oat ovens	121.4
Borden	FL	3048	Phosphate fertilizer production and boilers	82.8
Youngstown Sheet Tube	IN	3312	Steel production	79.1
[2]White Pine Copper	MI	1021	Copper smelting	77.2
AMOCO	IN	2911	Boilers	56.5
Union Carbide	OH	3312	Boilers	48.0
[3]St. Joe Lead	MO	3332	Lead smelting	47.7
Alcoa	TX	3334	Boilers	47.5
PPG	OH	2812	Boilers	46.2
Mead	OH	2621	Boilers	44.7
Diamond Shamrock	OH	2819	Boilers	39.2
Inland Steel	IN	3312	Boilers	38.6
[3]Getty Oil	DE	2911	Cat crackers and sulfuric acid plant	37.0
Texaco	TX	2911	Process heaters	34.2
Weirton Steel	WV	3312	Boilers	31.1
Cities Service	LA	2911	Boilers	30.2
Shell	IL	2911	Boilers, heaters, and cat crackers	30.2
Tennessee Eastman	TN	2818	Boilers	29.8

CONTINUED

[1] Based on 1977 survey
[2] SO_2 emissions at full capacity - operation has been at 1/2 capacity recently.
[3] SO_2 emissions different than reported in MAP3S - confirmed by telephone.

TABLE 3-3. (Continued)

Company	Plant Location	SIC Code	Major SO_2 Emitting Processes	Total Plant SO_2 Emissions (Thousands of Tons Per Year)
Clinton Corn	IA	2042	Boilers	29.5
Atlas Cement	MO	3241	Cement kilns	28.6
Gulf Oil	TX	2911	Boilers, elemental sulfur production, and fluid crackers	27.9
Phillips Petroleum	TX	2911	Fluid crackers, elemental sulfur production, and process heaters	27.5
Bethlehem Steel	MD	3312	Iron production	27.2
Virginia Pulp and Paper	MD	2621	Boilers and sulfite pulping	26.5
Monsanto	AL	2818	Boilers	25.9
Huron Cement	MI	3241	Cement kilns	25.7
Stauffer Chemical	TX	2819	Sulfuric acid production	25.5
US Steel	IN	3312	Boilers and iron production	22.7
AMOCO	TX	2911	Process heaters, boilers and fluid crackers	22.4
Whippany Paper	NJ	2645	Boilers	21.9
Sinclair Koppers	PA	3079	Boilers	21.8
Inland Steel	IN	3312	Boilers	21.7
Green Products	IA	2042	Alfalfa dehydration	21.6
Staley Mfg.	IL	2046	Boilers	21.4
Shell Chemical	TX	2819	Elemental sulfur production and boilers	21.0

CONTINUED

TABLE 3-3. (Continued)

Company	Plant Location	SIC Code	Major SO_2 Emitting Processes	Total Plant SO_2 Emissions (Thousands of Tons Per year)
PPG	WV	2812	Boilers	20.9
Dow Chemical	MI	2800	Boilers	20.6
Standard Oil of Ohio	OH	2911	Fluid crackers, flares, and process heaters	20.2

TABLE 3-4. INDUSTRIAL SO_2 EMISSIONS FROM 39 LARGEST SO_2 EMITTERS *

Process	SO_2 Emissions (10^3 Tons Per Year) Per Process	Total	Percent of Total
Boilers		695.3	43.1
Coal-fired (>100 MW_t)	(392.4)		
Coal-fired (<100 MW_t)	(86.9)		
Oil-fired	(172.6)		
Gas-fired	(43.4)		
Metals Industry (excluding boilers)		543.2	33.7
Copper smelting	(235.9)		
Iron and steel	(115.3)		
Coke metallurgy	(99.2)		
Lead smelting	(85.4)		
Aluminum	(3.1)		
Other	(4.3)		
Other Industrial Processes (excluding boilers)		350.0	21.7
Cat crackers	(71.3)		
Process heaters	(60.3)		
Cement kilns	(54.2)		
Sulfuric acid	(49.7)		
Phosphate fertilizer	(41.8)		
Sulfur plants	(33.9)		
Alfalfa dehydration	(21.6)		
Flares	(8.9)		
Sulfite pulping	(7.0)		
Sludge conversion	(1.3)		
Unclassified		25.5	1.5
		1614.0	100.0

* Based on 1977 survey

TABLE 3-5. DISTRIBUTION BY SIZE AND FUEL TYPE OF INDUSTRIAL BOILERS FROM 39 LARGEST EMITTERS

Boiler Size* (MW_t)	FUEL TYPE					
	Coal	Residual Oil	Distillate Oil	Gas	Unclassified	Total
less than 30	3	33	2	17	6	61
30 - 49.9	15	12	3	3	1	34
50 - 74.9	15	9	2	12	1	39
75 - 99.9	10	10	4	9	1	34
100 - 124.9	5	7	-	5	-	17
125 - 149.9	19	7	-	2	-	28
150 - 174.9	8	2	5	-	-	15
175 - 199.9	1	1	1	2	-	5
200 - 224.9	1	1	-	-	-	2
225 - 249.9	6	1	1	-	-	8
250 - 274.9	3	1	-	-	-	4
350 - 374.9	3	-	-	-	-	3
525 - 549.9	-	3	-	-	-	3
575 - 599.9	-	1	-	-	-	1
650 - 674.9	-	1	-	-	-	1
Unclassified	8	-	1	-	-	9
TOTAL	97	89	19	50	9	264

*Boiler Size given as heat input.

to be similar to the nationwide distribution of industrial water-tube boilers [3]; and (4) the percent sulfur in coal, oil, and gas was assumed to be the same as the fuel-weighted averages discussed in Section 3.2.2.

The 264 boilers characterized in Section 3.2.2 emitted a total of 695.3 thousand tons of SO_2 per year: 479.3 thousand TPY, or 68.9 percent from coal; 172.6 thousand TPY, or 24.8 percent from oil; and 43.4 thousand TPY, or 6.3 percent from gas. Applying these percentages to the 2 million tons of SO_2 per year emitted from the remaining 218 plants resulted in a distribution of 1,378,000 tons of SO_2 per year from coal-fired boilers, 496,000 tons of SO_2 per year from oil-fired boilers, and 126,000 tons of SO_2 per year from gas-fired boilers.

The boiler population was distributed by size in accordance with a distribution reported by PEDCo Environmental, Inc. (Tables C-70 through C-76).[4] Information contained therein is summarized in Table 3-6. Boilers with capacities below 30 MW_t were ignored. The boilers already characterized in Section 3.2.2 (Table 3-5) were subtracted from the boiler population in Table 3-6 to yield the number of potential boilers remaining nationwide (see Table 3-7).

It has previously been determined that SO_2 emissions were to be distributed among coal-, oil-, and gas-fired boilers in the amounts of 1,378,000; 496,000; and 126,000 tons per year, respectively. The information in Table 3-7 was used to distribute these emissions among the size categories. The boiler size in MW_t was multiplied by the potential number of boilers to give the total heat input capacity (in gigawatts) within a fuel and boiler size classification. The total heat input capacity was then used to apportion the total SO_2 emissions per year between the size classifications for each fuel type. The results are summarized in Table 3-8.

TABLE 3-6. DISTRIBUTION OF INDUSTRIAL WATER-TUBE BOILERS (>30 MW_t capacity) IN THE U.S. BY SIZE AND FUEL

Size Range MW_t (10^6Btu/hr)	Average Size MW_t (10^6Btu/hr)	Coal	Oil	Gas	Total
30-75 (100-250)	45 (150)	1181	1209	1443	3833
75-150 (250-500)	96 (325)	326	286	302	914
150-440 (500-1500)	220 (750)	81	60	96	237
>440 (>1500)	700 (2400) coal & oil	16	9	—	61
	1265 (4300) gas	—	—	36	
	TOTAL	1604	1564	1877	5045

TABLE 3-7. POTENTIAL BOILERS AFTER ACCOUNTING FOR THE BOILERS FOUND IN THE 39 LARGEST SO_2 EMITTERS

Average Size (MW_t)	Coal	Oil	Gas
45	1151	1183	1428
96	292	258	286
220	59	47	94
700 (coal, oil)	16	4	—
1265 (gas)	—	—	36
Total	1518	1492	1844

TABLE 3-8. DISTRIBUTION OF SO_2 EMISSIONS BY FUEL AND BOILER SIZE

Size (MW_t)	Coal				Oil				Gas				All Fuels
	Potential Boilers[a]	Total Capacity Gigawatts	Percent of Total Capacity	10^3 Tons SO_2/Yr	Potential Boilers[a]	Total Capacity Gigawatts	Percent of Total Capacity	10^3 Tons SO_2/Yr	Potential Boilers[a]	Total Capacity Gigawatts	Percent of Total Capacity	10^3 Tons SO_2/Yr	Total 10^3 Tons SO_2/Yr
45	1151	51.8	49.8	686	1183	53.2	58.4	290	1428	64.3	40.7	51	1027
96	292	28.0	26.9	371	258	24.8	27.2	135	286	27.5	17.4	22	528
220	59	13.0	12.5	172	47	10.3	11.3	56	94	20.7	13.1	17	245
700 (coal, oil) 1265 (gas)	16	11.2	10.8	149	4	2.8	3.1	15	36	45.5	28.8	36	200
TOTAL		104.0	100.0	1378		91.1	100.0	496		158.0	100.0	126	2000[b]

[a] Nationwide less boilers in largest 39 SO_2 emitters.

[b] The actual total of 1996 x 10^3 tons per year was rounded to 2000 x 10^3 tons per year.

Next, the number of equivalent boilers* was calculated. Several assumptions were made at this point:

- Heating values for

  Coal = 11,500 Btu/lb
  Oil = 18,500 Btu/lb
  Gas = 1,000 Btu/cu ft

- 0.6 boiler capacity utilization factor,
- 95 percent of sulfur in fuel emitted as SO_2, and
- average sulfur contents for

  Coal = 2.41 percent
  Oil = 1.64 percent
  Gas = 0.80 percent

The number of equivalent boilers was calculated by dividing the tons of SO_2 emitted annually (from Table 3-8) by the tons of SO_2 emitted annually by each boiler. For example, a 45 MW_t (150 x 10^6Btu/hr) coal-fired boiler will emit:

$$150 \times 10^6 \frac{Btu}{hr} \times 8760 \frac{hr}{yr} \times 0.6 \times \frac{1 \text{ lb coal}}{11{,}500 \text{ Btu}} \times 0.0241 \frac{\text{lb sulfur}}{\text{lb coal}}$$

$$\times \frac{2 \text{ lb } SO_2}{\text{lb sulfur}} \times \frac{1 \text{ ton}}{2000 \text{ lb}} \times 0.95 = 1.6 \text{ tons of } SO_2 \text{ per year}$$

Therefore, there would be 686,000 tons SO_2 per year (from Table 3-8) divided by 1.6 tons of SO_2 per year per boiler, or the equivalent of 429 boilers (with capacity of 45 MW_t) firing coal. The results of these distribution calculations are summarized in Table 3-9.

3.2.4 Summary of Emissions from the 257 Plants Emitting More than 5,000 Tons of SO_2 Per Year

The SO_2 emissions from the 39 largest emitters, characterized in Section 3.2.2, were combined with the equivalent boiler emissions (discussed in Section 3.2.3), resulting in the final characterization of industrial sector emissions of SO_2 presented in Table 3-10. Table 3-11 summarizes the final combined boiler population, and Table 3-12 summarizes the boiler emissions.

* The number of boilers in each size and fuel category that would yield the calculated annual SO_2 emissions given the average boiler size, fuel sulfur content, and capacity utilization factor.

TABLE 3-9. SIZE DISTRIBUTION OF BOILERS NEEDED TO ACCOUNT FOR TWO MILLION TONS[a] OF SO_2 EMITTED PER YEAR FROM PLANTS EMITTING BETWEEN 5,000 AND 20,000 TONS/YEAR OF SO_2

Average Boiler Size (MW_t)	COAL			OIL			GAS		
	10^3 Tons SO_2/Yr	10^3 Tons SO_2/Yr/Boiler	Approximate Number of Boilers[b]	10^3 Tons SO_2/Yr	10^3 Tons SO_2/Yr/Boiler	Approximate Number of Boilers[b]	10^3 Tons SO_2/Yr	10^3 Tons SO_2/Yr/Boiler	Approximate Number of Boilers[b]
45	686	1.6	429	290	1.1	264	51	0.6	85
96	371	3.4	109	135	2.3	59	22	1.3	17
220	172	7.8	22	56	5.4	10	17	2.9	6
700 (coal, oil)	149	24.9	6	15	17.1	1	-	-	-
1265 (gas)	-	-	-	-	-	-	36	16.9	2
Total	1378		566	496		334	126		110

Average Boiler Size (MW_t)	TOTAL	
	Approximate Number of Boilers[b]	10^3 Tons SO_2/Yr
45	778	1027
96	185	528
220	38	245
700 (coal, oil)	7	164
1265 (gas)	2	36
Total	1010	2000

[a] The actual total of 1996 x 10^3 tons per year was rounded to 2000 x 10^3 tons per year.

[b] The number of boilers in each size category that would yield the annual SO_2 emissions derived in Table 3-8 given the fuel quality and average boiler size and capacity factor discussed in the text.

TABLE 3-10. SUMMARY OF COMBINED SO_2 EMISSIONS FROM 257 PLANTS

Process	Emissions (Thousands of Tons SO_2 Per Year)
Boilers	2695.3
Metal Industry (excluding boilers)	543.2
Other Industrial Processes (excluding boilers)	350.0
Unclassified	25.5
Total	3614.0

TABLE 3-11. SUMMARY OF COMBINED BOILER POPULATION FROM 257 PLANTS (Actual from Top 39 Emitters + Calculated From Other 218 Emitters)

Average Boiler Size (MW_t)*	Coal	Oil	Gas	Unclassified	Total
Less than 30	3	35	17	6	61
45 (30-75)	459	290	100	2	851
96 (75-150)	143	87	33	1	264
220 (150-440)	44	23	8	—	75
700 (coal, oil) 1265 (gas) (> 440)	6	6	2	—	14
Unclassified	8	1	—	—	9
Total	663	442	160	9	1274

*Numbers in parentheses indicate the size range in MW_t.

TABLE 3-12. SUMMARY OF COMBINED BOILER SO_2 EMISSIONS

Source	SO_2 Emissions (Thousands of Tons Per Year) Coal	Oil	Gas	Total
Boilers from Largest 39 SO_2 Emitters	479	173	43	695
"Boilers" from Remaining 218 SO_2 Emitters (Calculated)	1378	496	126	2000
Total	1857	669	169	2695

SECTION 4

SO_2 EMISSION REDUCTION PROCESSES

Several techniques have been used to reduce SO_2 emissions from industrial sources. Sulfur dioxide emissions from industrial combustors have been reduced by two general techniques--pre- or post-combustion cleaning processes. The most commonly used pre-combustion processes are physical coal cleaning for coal-fired combustors and oil desulfurization for oil-fired combustors. These processes reduce SO_2 emissions by reducing the level of sulfur in the fuel prior to combustion. Post-combustion SO_2 emission reduction is commonly achieved with flue gas desulfurization (FGD) technology. Some boiler operators limit SO_2 emissions without cleaning processes by firing low sulfur coal and oil.

Sulfur dioxide emissions from non-boiler sources (such as in the metals industry) can be reduced by FGD processes or by conversion of the SO_2 in the effluent gases to sulfuric acid or elemental sulfur via the appropriate technology. However, the use of FGD processes is the most commonly implemented technique. FGD processes can also be used to reduce SO_2 emissions from industrial process heaters and catalytic crackers. The various SO_2 emission reduction alternatives are described below.

4.1 PHYSICAL COAL CLEANING

Physical coal cleaning is not a control mechanism which can be directly implemented by a boiler operator; instead, it is a group of mechanical processes that coal producers use to yield cleaner coal.[5] This process involves removing the pyritic (inorganic) sulfur from the coal by physical means. The mechanical processes commonly found in a physical coal cleaning facility are:

- Crushing and grinding,
- Screening,
- Coarse coal separation,
- Fine coal separation,
- Dewatering and drying,
- Refuse handling and disposal, and
- Storage and handling.

The various unit operations can be combined to yield five general levels of coal preparation. These levels of coal preparation are:

- Level 1 - Breaking for top size control and for removal of coarse refuse.
- Level 2 - Coarse beneficiation - where larger fractions of coal (plus 3/8 inch) are treated. The separated and untreated minus 3/8 inch portion of the coal is combined with the cleaned coarse coal for shipment.
- Level 3 - Fine and coarse size beneficiation - where all the feed is wetted. Plus 28M is beneficated; 28M x 0 material is dewatered and either shipped with clean coal or discarded as refuse.
- Level 4 - Very fine beneficiation - where all the feed is wetted and washed. Thermal drying of 1/4" x 0 fraction generally is required to limit moisture content.
- Level 5 - Full beneficiation which consists of rigorous cleaning. It requires crushing the raw coal to much finer sizes and results in multistage cleaning and multiproduct operation. A plant optimized to remove both pyritic sulfur and ash from amenable coals would most likely be of this type.[6]

A flow diagram of a Level 3 physical coal preparation facility is presented in Figure 4-1. Although the five levels vary in complexity and, consequently, in sulfur removal and energy recovery capabilities, the maximum sulfur removal exhibited by each is limited by the coal's pyritic

sulfur content. This limitation reflects the inability of a physical process to remove organically-bound sulfur. Typically, about 25-35 percent of the total sulfur in coal can be removed by the higher levels (Level 3, 4, and 5) of physical coal cleaning.

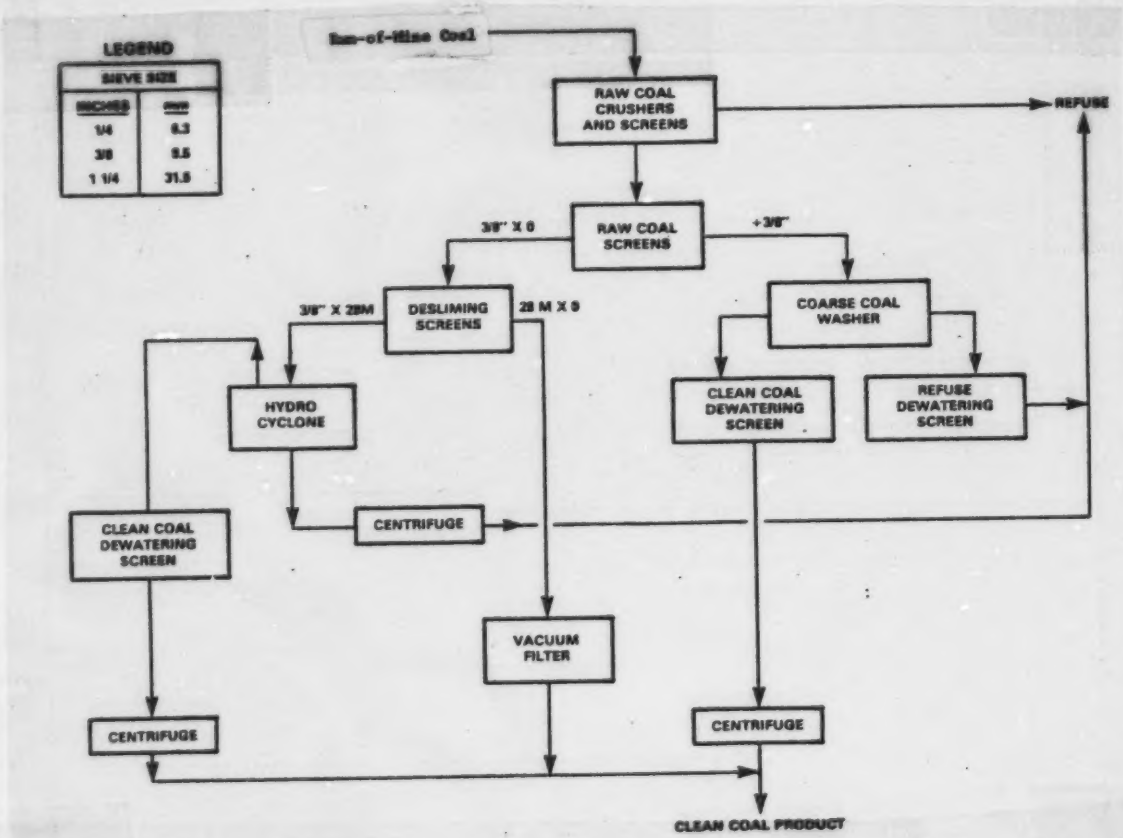

FIGURE 4-1. LEVEL 3 COAL PREPARATION PLANT FLOW DIAGRAM[7]

4.2 OIL DESULFURIZATION

There are two general techniques which are currently used to convert a heavy, high-sulfur oil to a low-sulfur fuel. The first technique, hydrotreating, involves contacting the oil with a catalyst and hydrogren to convert chemically-bonded sulfur and nitrogen to gaseous hydrogen sulfide and ammonia, respectively. The second technique involves processes which convert heavy, high-sulfur residual oils to clean, low-sulfur gas.[8] In this study, only the hydrotreating (or hydrodesulfurization) of residual oil was considered.

In a typical hydrodesulfurization (HDS) process (Figure 4-2), residual oil feed is filtered to remove rust, coke, and other suspended material. It is then mixed with hydrogen, heated to a temperature ranging from 650°F to 850°F, and passed over one or more catalytic reaction beds. The number of reaction beds required is dependent on the degree of desulfurization desired. When oils containing high levels of metals (nickel and vanadium) are treated, a guard reactor is utilized to remove most of the metals, therefore, minimize the contamination of the more valuable catalyst used in the hydrodesulfurization reactors. In the reaction beds, hydrogen reacts with sulfur compounds to yield H_2S, nitrogen to yield ammonia, and organometals (primarily Ni and V) compounds to yield sulfides of these metals. Most of the metal sulfides deposit on the surface or in the pores of the catalyst and slowly deactivate the catalyst. Other reactions that occur between hydrogen and components in the residual oil lead to a reduction in the carbon residue of thr product oil.[9]

Data reported in literature indicate that the size of HDS units ranges from several thousands of barrels of oil per day (B/D) to one hundred thousand barrels per day. The majority of new installations have capacities ranging from 25,000-75,000 B/D. Because the maximum capacity that can be built into a single process train is approximately 25,000-30,000 B/D, HDS plants are likely to be built in one, two, or three units for total capacities of 25,000-75,000 B/D. Reported data also indicates that single-stage (one reaction bed) units are used to reduce sulfur in the oil to about 0.8 percent, two-stage units to about 0.3 percent, and either two- or three-stage units with a guard reactor to as low as 0.1 percent[11,12,13] for some resids.

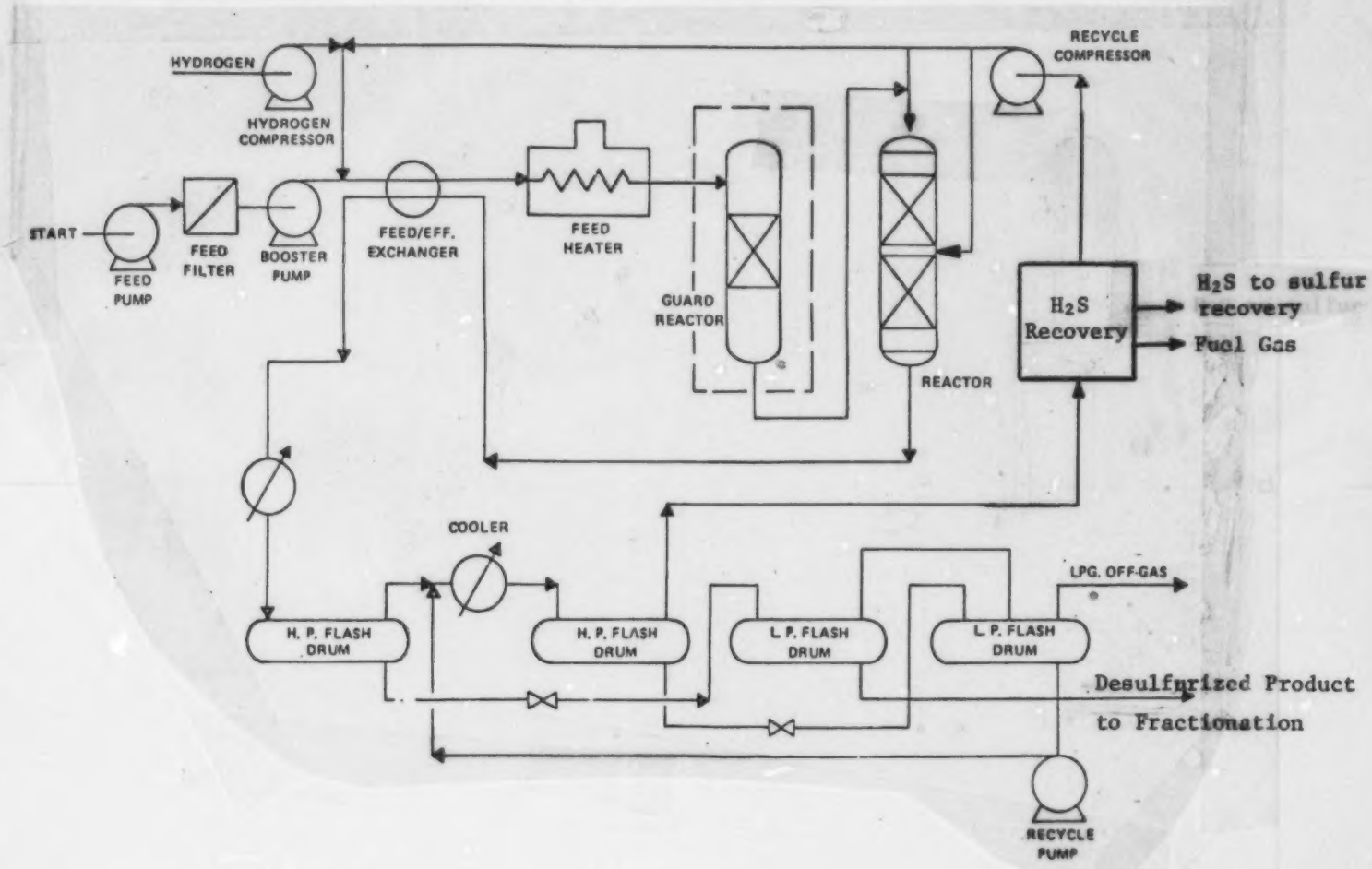

Figure 4-2. Typical Residual Oil Hydrodesulfurization Process[10]

4.3 FLUE GAS DESULFURIZATION (FGD)

There are over 100 FGD processes currently in various stages of development; however, only six of these processes are in commercial use in the U.S. In addition, there are five other FGD processes that are currently at an advanced stage of demonstration.[14] Of the eleven commercial and advanced demonstration FGD processes, the three systems most applicable to industrial boilers in the U.S. are once-through sodium, double (dual) alkali, and lime/limestone scrubbing. The relative use of these three processes on industrial boilers is summarized in Table 4-1. The data in this table indicate that once-through sodium and double alkali processes are the FGD processes most commonly used on industrial boilers. Application of once-through sodium scrubbing may be limited by disposal of the waste liquor generated by the process. The double alkali process has been successfully applied to small industrial boilers, and its application is increasing. The limestone process was chosen as the basis for the FGD analyses developed in this study because more is known about limestone FGD investment/operating costs over wide variations in boiler capacity[15]. In addition, double alkali process economics are essentially equivalent to those of limestone for an FGD system applied to an 8.8 MW_t boiler, and are within eight percent at 58.6 MW_t.[16] Therefore, the cost impacts estimated in this study should be representative of utilizing either lime/limestone or double alkali FGD systems.

TABLE 4-1. SUMMARY OF THE USE OF FGD PROCESSES ON INDUSTRIAL BOILERS[17]

PROCESS	PERCENT OF CAPACITY		
	Operational	Construction	Total Market
Once-Through Sodium	76	54	72
Double Alkali	11	35	16
Lime/Limestone	3	-	2
Others	10	11	10

A simplified flow diagram for the lime/limestone process is presented in Figure 4-3. A slurry of lime (CaO) or limestone ($CaCO_3$) is used to absorb SO_2 in a wet scrubber. Alkaline fly ash, if present, contributes alkalinity in the form of soluble calcium, magnesium, and/or sodium oxides which participate in the SO_2 removal reactions. Approximately 90 percent SO_2 removal is achievable with these FGD systems.* The chemistry is quite complex, involving many side reactions. Calcium sulfite ($CaSO_3$) is formed, some of which is oxidized to calcium sulfate ($CaSO_4$) according to the following overall reactions:

Lime Systems

$$SO_2(g) + CaO(s) + \tfrac{1}{2}H_2O \longrightarrow CaSO_3 \cdot \tfrac{1}{2}H_2O(s)$$

$$SO_2(g) + CaO(s) + 2H_2O + \tfrac{1}{2}O_2(g) \longrightarrow CaSO_4 \cdot 2H_2O(s)$$

Limestone Systems

$$SO_2(g) + CaCO_3(s) + \tfrac{1}{2}H_2O \longrightarrow CaSO_3 \cdot \tfrac{1}{2}H_2O(s) + CO_2(g)$$

$$SO_2(g) + CaCO_3(s) + 2H_2O + \tfrac{1}{2}O_2(g) \longrightarrow CaSO_4 \cdot 2H_2O(s) + CO_2(g)$$

The extent of oxidation can vary from almost zero to as high as 90 percent. This value depends upon liquor pH, SO_2 and oxygen concentration in the flue gas, and fly ash composition.

The calcium sulfite and sulfate crystals precipitate in a reaction vessel or hold tank which is designed to provide adequate residence time for solids precipitation, as well as for dissolution of the alkaline additive. The hold tank effluent (which contains 10-15 percent solids) is recycled to the scrubber to absorb additional SO_2. A slipstream from the hold tank is sent to a solid-liquid separator to remove the precipitated solids from the system. The waste solids are generally disposed of by ponding or landfill, and the supernatent liquor is returned to the scrubber.

*Tests on one lime FGD system and two double alkali systems have confirmed that these systems can achieve approximately 90 percent SO_2 removal.

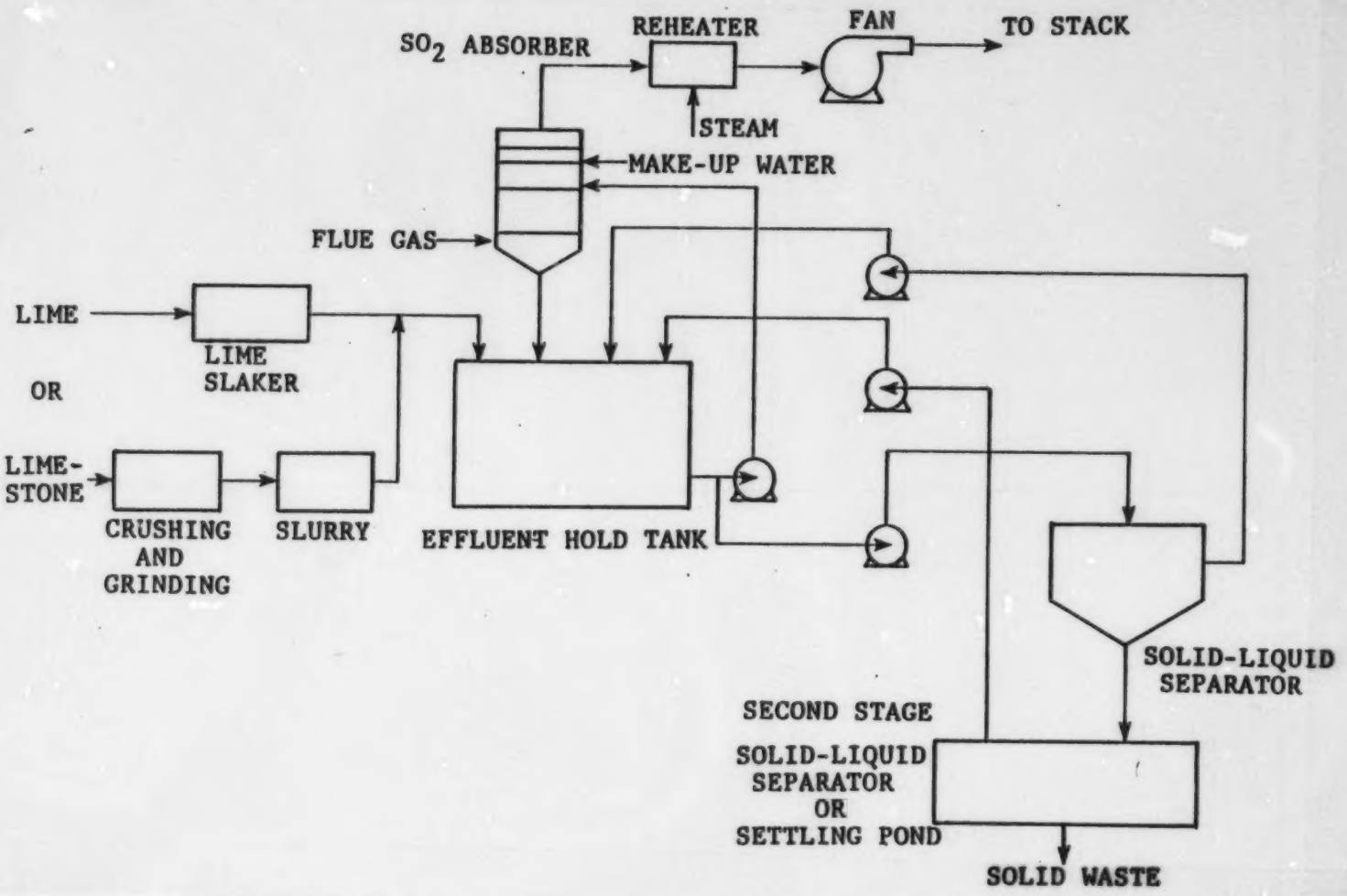

FIGURE 4-3. SIMPLIFIED FLOW DIAGRAM FOR LIME/LIMESTONE WET SCRUBBING[18]

SECTION 5

ESTIMATION OF SO_2 EMISSION REDUCTION AND CONTROL COSTS

5.1 BASES FOR ANALYSES

Several general assumptions were made so that the cost* of reducing SO_2 emissions from sources within the industrial sector considered in this study could be estimated. These assumptions are presented below.

In this study, low-sulfur coal (<2% S) was assumed to be an SO_2 control option only for boilers actually firing this coal within the 39 plants emitting greater than 20,000 tons per year of SO_2. No additional SO_2 controls, and thus no reduction in SO_2 emissions, were assumed for these 31 boilers.

Physically cleaned coal was the SO_2 control process applied to coal-fired boilers having capacities less than 75 MW_t (thermal input) and not burning low sulfur fuel. The average sulfur level of the uncleaned coal was assumed to be 3.0 percent. This was the average sulfur level of the coal from the top 39 emitters excluding the low sulfur coal users (<2.0 percent). It was assumed that a boiler operator would buy clean coal from a major producer; consequently, as the result of using clean coal, the boiler operator would pay a premium in addition to the cost of the raw coal. The physical cleaning process was assumed to reduce the sulfur level of the raw coal by 30 percent. The premium incurred by the boiler operator was estimated to be $4.28/ton (in 1980 dollars).[19,20,21] This cost strictly represents the cost of preparation and does not include the cost of run-of-mine (ROM) coal, transportation, or taxes.

*The capital investment and annual costs are significant only to two figures; however, results are reported to the last whole significant figure to be consistent with other similar studies.

In this study, it was assumed that low sulfur oil could be used for SO_2 control on all oil-fired boilers. It was also assumed that, like physically cleaned coal, low sulfur oil would be bought from a major producer. The producer would be paid a premium for upgrading the residual oil. Generally, the cost of upgrading residual oil by hydrodesulfurization is dependent on the levels of sulfur and heavy metals (Ni and V) in the residual oil and the sulfur level in the product oil. The average sulfur level of the residual oil used in oil-fired boilers was estimated to be about 1.64 percent, based on MAP3S data. The low sulfur oil was assumed to have a sulfur content of 0.8 percent. The sulfur premium that would be paid by the boiler operator was estimated to be about $2.50 per barrel (based on hydrodesulfurization costs).

The limestone FGD process was applied as the SO_2 control process for all coal-fired boilers having capacities greater than 75 MW_t. Application of this process would require that it be retrofitted to the boilers. The cost of using an FGD process is primarily a function of the percent of sulfur in the fuel, the capacity of the boiler (which establishes the flue gas flowrate), and the SO_2 removal desired. For coal-fired boilers, the coal was calculated from MAP3S data to have an average sulfur level of 2.41 percent. The latest available cost data[22] are based on boilers firing 3.5 percent sulfur coal with FGD systems achieving 90 percent sulfur removal. This information was assumed applicable to boilers burning 2.41 percent sulfur coal and was used to develop capital and annual costs as a function of boiler size for new FGD installations obtaining 90 percent SO_2 removal. Reported data also indicate that the capital cost of a retrofit FGD system is about 20-30 percent more expensive than the cost of a system that is installed as part of a new boiler.[23] Consequently, the capital cost of a retrofit FGD process was determined by multiplying the cost of a new FGD system (from Figure 5-1) by a factor of 1.3. The annual costs in retrofits were estimated by summing the annual costs for a new FGD system applied to a new boiler plus the incremental capital-related costs resulting from the 30 percent higher capital investment for a retrofitted facility. The resulting data are graphically presented in Figures 5-1 and 5-2. No attempt was made to estimate remaining useful life

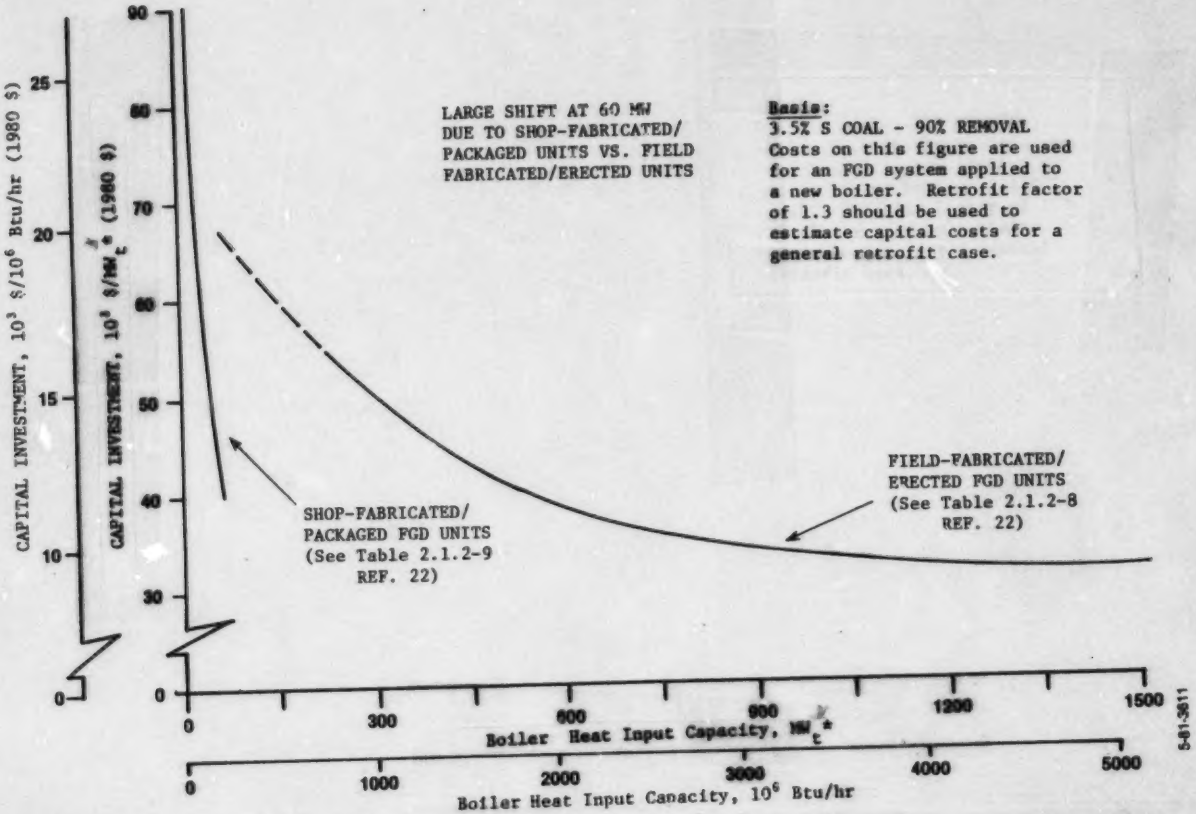
CAPITAL INVESTMENT, 10^3 $/10^6 Btu/hr (1980 $)
CAPITAL INVESTMENT, 10^3 $/MW_c$* (1980 $)
LARGE SHIFT AT 60 MW DUE TO SHOP-FABRICATED/ PACKAGED UNITS VS. FIELD FABRICATED/ERECTED UNITS
Basis:
3.5% S COAL - 90% REMOVAL
Costs on this figure are used for an FGD system applied to a new boiler. Retrofit factor of 1.3 should be used to estimate capital costs for a general retrofit case.
FIELD-FABRICATED/ ERECTED FGD UNITS (See Table 2.1.2-8 REF. 22)
SHOP-FABRICATED/ PACKAGED FGD UNITS (See Table 2.1.2-9 REF. 22)
Boiler Heat Input Capacity, MW_c*
Boiler Heat Input Capacity, 10^6 Btu/hr
5-61-3611

FIGURE 5-1. CAPITAL INVESTMENT FOR A LIMESTONE FGD SYSTEM (APPLIED TO A NEW BOILER)

*1 MW_c = 3.412 x 10^6 Btu/hr.

*1 MWc = 3.412 x 10^6 Btu/hr

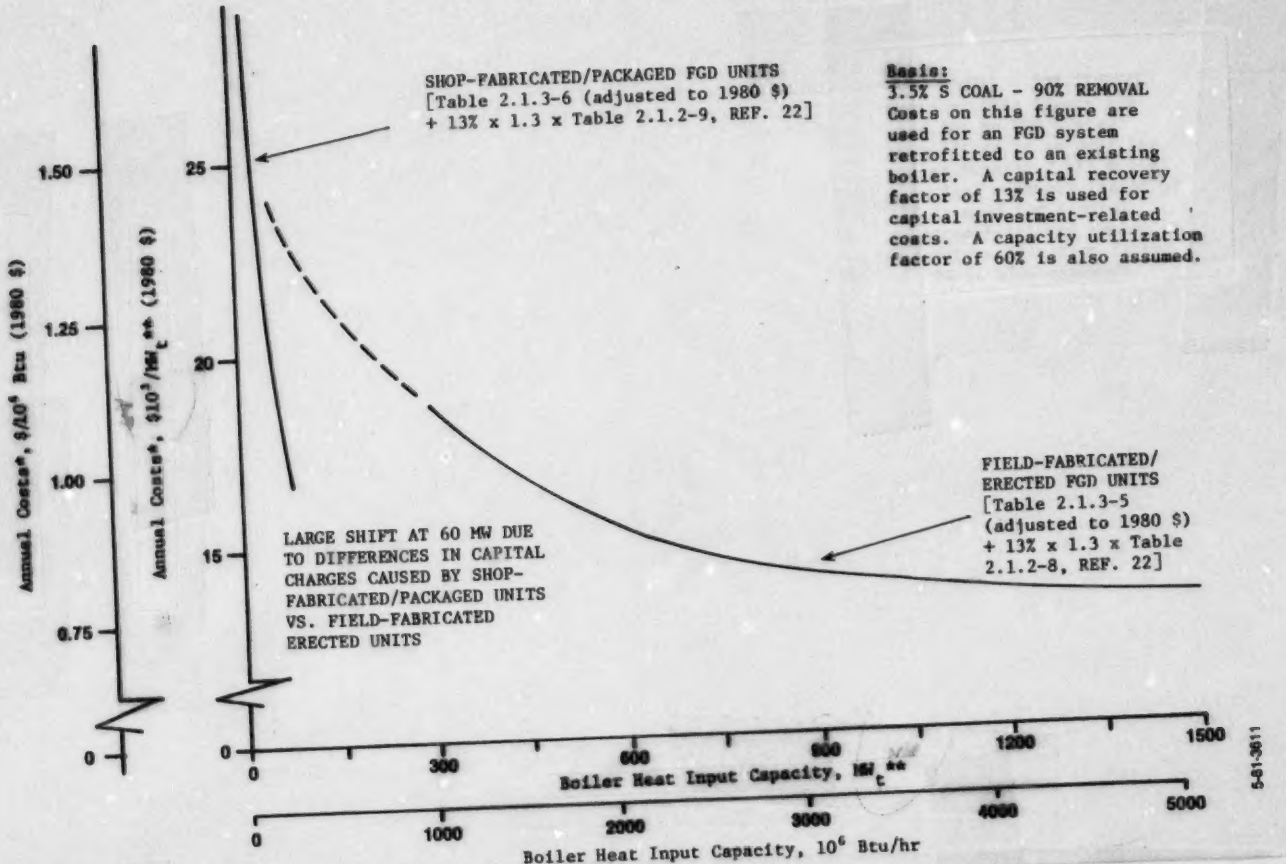
SHOP-FABRICATED/PACKAGED FGD UNITS
[Table 2.1.3-6 (adjusted to 1980 $)
+ 13% x 1.3 x Table 2.1.2-9, REF. 22]
Basis:
3.5% S COAL - 90% REMOVAL
Costs on this figure are used for an FGD system retrofitted to an existing boiler. A capital recovery factor of 13% is used for capital investment-related costs. A capacity utilization factor of 60% is also assumed.
FIELD-FABRICATED/ ERECTED FGD UNITS
[Table 2.1.3-5 (adjusted to 1980 $)
+ 13% x 1.3 x Table 2.1.2-8, REF. 22]
LARGE SHIFT AT 60 MW DUE TO DIFFERENCES IN CAPITAL CHARGES CAUSED BY SHOP-FABRICATED/PACKAGED UNITS VS. FIELD-FABRICATED ERECTED UNITS
Annual Costs*, $/10^6 Btu (1980 $)
Annual Costs*, $10^3/MW_t** (1980 $)
1.50
1.25
1.00
0.75
0
25
20
15
0
0
300
600
900
1200
1500
Boiler Heat Input Capacity, MW_t**
0
1000
2000
3000
4000
5000
Boiler Heat Input Capacity, 10^6 Btu/hr
5-81-3611

FIGURE 5-2. ANNUAL COSTS FOR A RETROFITTED LIMESTONE FGD SYSTEM

* Annual Costs are expressed two ways:

- $/10^6 Btu is the annual costs ($/year) divided by the annual boiler heat input (Btu's/year).
- $/MW_t is the annual costs ($/year) divided by the boiler capacity (MW_t).

** 1 MW_t = 3.412 x 10^6 Btu/hr.

for the sources.* Obviously, a shorter remaining useful life would significantly increase the resulting annual costs (in $/year and $/$10^6$ Btu).

The limestone FGD process was also assumed to be retrofitted to most non-boiler sources in the metals and process industries for all processes emitting greater than 1000 tons/per year SO_2 from a single point source. To estimate the cost of reducing SO_2 emissions from these industries, each non-boiler source was first converted to an equivalent boiler capacity based on the gas flow rates from MAP3S data. Then the same costing procedure described above for boilers was used.

In addition, based on previous detailed studies,[24,25] sulfuric acid plants and fugitive cleanup were assumed to be installed as controls for two smelting operations. Investment and annual cost data were abstracted from these reports and updated to a 1980 dollar basis.

A summary of the various control processes and their applications is presented in Table 5-1. Detailed calculations are contained in Appendices I, II, and III.

5.2 IMPACT AND COST OF CONTROLS FOR PLANTS EMITTING MORE THAN 5,000 TONS PER YEAR OF SO_2**

As Table 5-1 shows, 31 boilers within the 39 plants emitting greater than 20,000 tons of SO_2 per year use low-sulfur coal (average sulfur content of 1.3 percent). The use of low-sulfur coal in these boilers results in annual SO_2 emissions of about 83,000 tons. No SO_2 controls were applied to these boilers.

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*The capital recovery factor was taken as 13 percent of capital investment and is based on a fifteen year FGD system life using the constant payment annuity formula with a 10 percent interest rate.

**The results do not include an analysis of the availability of physically cleaned coal and desulfurized fuel oil, nor the age and useful lives of the sources.

TABLE 5-1. SUMMARY OF SO_2 CONTROL APPLICATIONS

Control Applied	Source Category	Type of Fuel Used	Avg. Sulfur Level in Fuel (%) [e]	Boiler Size (MW)	Number of Affected Boilers
None[a]	Boilers	Coal	1.3	All sizes	31[f]
Physically Cleaned Coal	Boilers	Coal	3.0	<75	449[f]
FGD (Limestone)[g]	Boilers	Coal	2.4	96	143
				220	44
				700	6
Desulfurization	Boilers	Oil	1.64	<75	325
				96	87
				220	23
				700	6
None	Boilers	Gas	0.8	<75	117
				96	33
				220	8
				1265	2
FGD[d]	Non-boiler sources in metals industry	-	-	25-644[b]	-
FGD	Non-boiler sources in process industry	-	-	17-1000[c]	-

[a] Boilers in the top 39 SO_2 emitting plants currently firing 2.0 percent or lower sulfur coal do not require controls.

[b] The capacities of non-boiler sources in the metals industry are equivalent to boilers of this size range.

[c] The capacities of non-boiler sources in the process industry are equivalent to boilers of this size range.

[d] Sulfuric acid plants were used as controls on two smelting operations where it was known that sulfuric acid plants actually exist.

[e] Before controls are applied.

[f] Nine boilers were unclassified as to size and nine boilers were unclassified as to fuel type. Fourteen of these boilers were found to be at sites that used low S coal exclusively. Thus the number of low S coal burning boilers were increased from 17 to 31. The other four unclassified size/fuel boilers were arbitrarily assigned to physically cleaned coal.

[g] Costs estimated in this category are for FGD systems applied to individual boilers. No attempt was made to duct two or more boilers together and then add a scrubber.

The application of physically cleaned coal as an SO_2 control process would affect 449 coal-fired industrial boilers* with capacities less than 75 MW_t. These uncontrolled boilers presently emit about 730,000 tons of SO_2 per year. The use of physically cleaned coal would reduce these uncontrolled emissions by about 30 percent, to a level of 511,000 tons/year. Approximately 12.2×10^6 tons of clean coal per year (or 16×10^6 tons of raw coal) would be required to achieve this reduction. As a result of the cleaning operation, the boiler operator would pay a coal producer a premium for clean coal above the price he already pays for run-of-mine (ROM) coal. Assuming this premium is $4.28/ton of clean coal, industry would incur a total annual premium of $46 million solely for coal preparation.

Uncontrolled coal-fired industrial boilers with capacities greater than 75 MW_t emit 1,044,000 tons of SO_2 per year. Applying FGD processes to these boilers would reduce the SO_2 emissions to 104,000 tons/yr, a 90 percent reduction. Retrofitting FGD systems to achieve this reduction would require an industry-wide capital investment of $2.02 billion. The annual cost of utilizing FGD technology to reduce SO_2 emissions would be $565 million per year.

Currently, oil-fired industrial boilers generate about 669,000 tons of uncontrolled SO_2 emissions per year. The use of low sulfur fuel oil would reduce the SO_2 emissions to a level of 326,000 tons/year. To achieve this reduction, about 128×10^6 barrels of low sulfur oil per year would be required. As discussed in Section 5.1, the premium paid by the boiler operator for a fuel oil with a sulfur content of 0.8 percent was taken as $2.50/bbl (based on resid hydrodesulfurization costs). Consequently, the total annual cost incurred by operators of oil-fired boilers as the result of this premium would be $314 million.

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*These are the calculated equivalent boilers presented in Table 3-11 (459) less than those boilers known to be firing low sulfur coal.

Uncontrolled non-boiler sources in the metals and process industries emit 543,000 tons of SO_2/year and 350,000 tons of SO_2/year, respectively. Retrofitting FGD systems and sulfuric acid process units to the non-boiler point sources emitting greater than 1000 tons per year SO_2 in the metals industry would reduce the SO_2 emissions to a level of 62,000 tons/year. To achieve this reduction, the metals industry would have to invest $420 million for retrofitting FGD systems to the emission sources. Operation of the FGD systems would result in an annual cost of $128 million. The use of FGD systems in the process industry for point sources emitting greater than 1000 tons per year SO_2 would reduce the uncontrolled SO_2 emissions from this industry to a level of 64,000 tons/year. The capital investment required to achieve this reduction would be about $850 million. The annual cost for these control systems would be $178 million.

The impacts and costs that result when various control processes are applied to industrial sources emitting greater than 5,000 tons/year of SO_2 are summarized in Table 5-2. The data in this table show that:

- the total uncontrolled SO_2 emissions from industrial sources within the ARMS region are approximately 3.6×10^6 tons/year,
- application of control processes to the major sources of SO_2 emissions in this region could reduce the SO_2 emissions to a level of about 1.30×10^6 tons/year, a 63 percent reduction,
- to obtain this 63 percent reduction, industry in the ARMS region would have to invest $3.0 billion for installing the various control processes and would incur annual costs of about $1.2 billion, and
- the cost effectiveness ($/ton SO_2 removed) for the controls evaluated ranged from $210 to $915/ton.

TABLE 5-2. SUMMARY OF IMPACT AND COST OF CONTROLS FOR PLANTS EMITTING MORE THAN 5,0CO TONS/YEAR OF SO_2

	SO_2 Emission Sources[f]				SO_2 Control Processes					
Source Category	Fuel Type	Boiler Size MW_t	Avg. Sulfur Level (%)	Uncontrolled SO_2 Emissions (10^3 Ton/Yr)	Control Applied	SO_2 Reduction Achieved (%)	Controlled SO_2 Emissions (10^3 Ton/Yr)	Capital Investment[g] ($10^6)	Annual Cost ($10^6)[e,g]	Cost Effectiveness[g] ($/Ton SO_2 Removed)
Boilers										
	Coal	-[c]	1.3	83	None	-	83	-	-	-
	Coal	<75	3.0	730	Physical Coal Cleaning	30	511	-	46[a]	210
	Coal	>75	2.41	1,044	FGD (Limestone)[h]	90	104	2,020	565	601
	Fuel Oil	All	1.64	669	Low sulfur fuel oil	51[b]	326	-	314[a]	915
	Gas	All	0.8	169	None	-	169	-	-	-
Non-Boiler Sources (Metals Industry)	-		-	543	FGD (Limestone)[d,i]	89	62	420	128	266
Non-Boiler Sources (Process Industry)	-		-	350	FGD (Limestone)[i]	82	64	580	178	622
TOTALS				3,588[j]		63[k]	1,319	3,020	1,231	542[k]

[a] The cost directly represents the premium paid by boiler operator for upgraded fuel.
[b] This reduction efficiency is set by assuming the use of 0.8 percent sulfur fuel oil down from an average level of 1.64 percent. The costs are based on resid hydrodesulfurization.
[c] Boilers in the top 39 SO_2 emitters that actually burn <2.0 percent sulfur coal.
[d] Includes two sulfuric acid plants.
[e] In this report, annual costs include annual O&M, overhead, utilities, etc., and annual capital-related charges equivalent to 0.13 times the total capital investment.
[f] Uncontrolled emissions for 1977.
[g] 1980 $.
[h] The cost effectiveness figures for FGD units applied to the boilers in the plants emitting between 5,000 and 20,000 tons per year of SO_2 can be calculated from data presented in Appendices I and II and are:

Average Capacity MW_t	Number of Boilers	Cost Effectiveness, $/Ton/$SO_2$ Removed
96	109	700
220	22	620
700	6	460

[i] FGD process applied to point sources emitting greater than 1000 tons per year SO_2.
[j] Excludes emissions from unclassified sources.
[k] Weighted average.

5.3 IMPACT AND COST OF CONTROLS FOR PLANTS EMITTING MORE THAN 20,000 TONS PER YEAR OF SO_2*

As discussed previously, the 39 plants emitting more than 20,000 tons/year of SO_2 account for about 1.6 million tons/year of SO_2. The impact and costs that result when various control processes are applied to these 39 industrial emitters are summarized in Table 5-3.

Comparison of Tables 5-2 and 5-3 shows the following:

	Plants Emitting More Than 20,000 Tons/Year	Plants Emitting More Than 5,000 Tons/Year
Uncontrolled SO_2 Emissions--excludes unclassified sources (10^6 Tons/Year)	1588	3588
Controlled SO_2 Emissions (10^6 Tons/Year)	402	1319
Net Reduction	1186	2269
Capital Investment ($\$10^6$)	1471	3020
Annual Operating Cost ($\$10^6$)	557	1225
Cost Effectiveness, \$/Ton SO_2 Removed	472	542

Marginal cost and investment calculations show that the investment and cost per ton of SO_2 removed is lower for the 39 plants emitting greater than 20,000 tons/year SO_2 than for the 218 plants emitting 5,000 to 20,000 tons/year SO_2. Again, the reader should bear in mind that numerous assumptions were made for the latter group of plants.

*The results do not include an analysis of the availability of physically cleaned coal and desulfurized fuel oil, nor the ages and useful lives of the sources.

TABLE 5-3. SUMMARY OF IMPACT AND COST OF CONTROLS FOR PLANTS EMITTING MORE THAN 20,000 TONS/YEAR OF SO_2

	SO_2 Emissions Sources[f]				SO_2 Control Processes					
Category	Fuel Type	Boiler Size MW_t	Avg. Sulfur Level (%)	Uncontrolled SO_2 Emissions (10^3 Ton/Yr)	Control Applied	SO_2 Reduction Achieved (%)	Controlled SO_2 Emissions (10^3 Ton/Yr)	Capital Investment[g] ($10^6)	Annual Cost ($10^6)[e,g]	Cost Effectiveness[g] ($/Ton SO_2 Removed)
Boilers										
	Coal	-[c]	1.3	83	None	-	83	-	-	-
	Coal	<75	3.0	44	Physical Coal Cleaning	30	31	-	3[a]	210
	Coal	>75	2.41	352	FGD (Limestone)	90	35	471	170	536
	Fuel Oil	All	1.64	173	Low Sulfur Fuel Oil	51[b]	84	-	81[a]	910
	Gas	All	0.8	43	None	-	43	-	-	-
Non-Boiler Sources (Metals Industry)	-		-	540	FGD (Limestone)[d,h]	89	62	420	128	266
Non-Boiler Sources (Process Industry)	-		-	350	FGD (Limestone)[h]	82	64	580	170	622
TOTALS				1,588[i]		75[j]	402	1,471	560	472[j]

[a] The cost directly represents the premium paid by boiler operator for upgraded fuel.
[b] This reduction efficiency is set by assuming the use of 0.8 percent sulfur fuel oil down from an average level of 1.64 percent.
[c] The costs are based on resid hydrodesulfurization.
[d] Boilers in the top 39 SO_2 emitters that actually burn <2.0 percent sulfur coal.
[e] Includes two sulfuric acid plants.
[f] In this report, annual costs include annual O&M, overhead, utilities, etc., and annual capital-related charges equivalent to 0.13 times the total capital investment.
[g] Uncontrolled emissions for 1977.
[h] 1980 $.
[i] FGD process applied to point sources emitting greater than 1000 tons per year SO_2.
[j] Excludes emissions from unclassified sources.
Weighted average.

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APPENDIX I

CAPITAL INVESTMENT AND ANNUAL COSTS
FOR
BOILER SO_2 EMISSIONS REDUCTION PROCESSES
IN
PLANTS EMITTING >5,000 TONS SO_2/YR

I. Physical Coal Cleaning

$4.28/ton[19,20,21] of cleaned coal is premium charged to boiler operator to purchase cleaned coal (S level reduced 30%).

12.2×10^6 tons/yr of clean coal required
3.0% S coal assumed in raw uncleaned coal
HHV of coal increased from 11,500 Btu/lb to 13,000 Btu/lb

$$12.2 \times 10^6 \ \frac{\text{Tons}}{\text{Yr}} \times \frac{11{,}500}{13{,}000} \times \frac{\$4.28}{\text{ton}} = \frac{\$46 \times 10^6}{\text{Yr}}$$

II. Oil Desulfurization

$2.50/BBL* of desulfurized oil (S level reduced to 0.8%) is the premium charged to boiler operator to purchase desulfurized oil.

$$669 \times 10^3 \ \frac{\text{Ton } SO_2}{\text{Yr}} \times \frac{32(S)}{64\ (SO_2)} \times \frac{1 \text{ Part Oil}}{0.0164 \text{ Parts S}^{**}} \times \frac{2 \times 10^3 \text{ Lb}}{\text{Ton}}$$

$$\times \frac{1 \text{ BBL}}{325 \text{ Lbs}} \times \frac{\$2.50}{\text{BBL}} = \frac{\$314 \times 10^6}{\text{Yr}}$$

*Based on hydrodesulfurization costs.
**Based on MAPS3 data.

III. FGD for Coal Burning Boilers >75 MWt

1. Capital Investment

Boiler Size,[a] MW_t	x	Cap. Invest.,[b] $\$10^3/MW_t$	x	# Boilers[a]	=	Total Cap. Invest., $\$10^6$
96		64		143		879
220		54		44		523
700		36		6		151
						1,553

Using a 1.3 retrofit factor

Total Cap Invest = $1553 \times 10^6 \times 1.3 = \$2.02 \times 10^9$

2. Annual Costs

Boiler Size,[a] MW_t	x	Annual Costs,[c] 10^3 Yr/MW_t	x	# Boilers[a]	=	Total Annual Costs, $\$10^6$/Yr
96		22.5		143		309
220		20.0		44		194
700		14.8		6		62
						565

a. Table 5-1
b. Figure 5-1
c. Figure 5-2

APPENDIX II

CAPITAL INVESTMENT AND ANNUAL COSTS
FOR
BOILER SO_2 EMISSIONS REDUCTION PROCESSES
IN
PLANTS EMITTING > 20,000 TONS SO_2/YR

I. Boiler Fuel Sulfur Content Distribution

- Coal Burning Boilers - All Sizes

% S in Coal	# Boilers		SO_2,10^3 Tons/Yr	
0.8	22	31	29.9	82.9
1.3	3		0.8	
1.6	6		52.2	
2.2	6		68.7	
2.5	4		20.8	
2.8	22		89.0	
3.2	14		44.8	
3.4	7		38.6	
3.8	5		25.9	
4.4	8		108.6	
	97		479.3	

- Coal Burning Boilers < 75 MW_t

% S in Coal	# Boilers	SO_2,10^3 Tons/Yr	
0.8	13	9.9	
1.3	3	0.8	
1.6	1	1.9	
2.8	10	24.9	Equivalent to 738 x 10^3 Tons/Yr of 3.0% S Coal
3.2	3	44.3 12.2	
3.4	3	7.2	
	33	56.9	

- Oil Burning Boilers - All Sizes

% S in Oil	SO_2, 10^3Tons/Yr
0.62	3.0
0.70	0.4
0.80	25.2
1.00	0.2
1.10	7.1
1.20	6.2
1.34	3.1
1.75	0.4
1.98	50.4
2.20	7.4
2.25	46.8
3.05	1.0
5.00	21.4
	172.6

- Gas Burning Boilers - All Sizes

% S in Gas	SO_2, 10^3Tons/Yr
0.15	1.2
0.23	1.7
0.48	1.1
0.64	5.5
0.91	12.3
1.30	0.6
1.50	11.8
1.70	9.2
	43.4

II. Physical Coal Cleaning

$4.28/ton[19,20,21] of cleaned coal is premium charged to boiler operator to purchase clean coal (S level reduced 30%).

738×10^3 tons/yr of clean coal required

3.0% coal assumed

HHV of coal increased from 11,500 Btu/Lb to 13,000 Btu/Lb

$$738 \times 10^3 \frac{\text{Tons}}{\text{Yr}} \times \frac{11{,}500}{13{,}000} \times \frac{\$4.28}{\text{Ton}} = \frac{\$2.8 \times 10^6}{\text{Yr}}$$

III. Oil Desulfurization

$2.50/BBL* of desulfurized oil (S level reduced to 0.8%) is the premium charged to boiler operator to purchase desulfurized oil.

$$172.6 \times 10^3 \frac{\text{Tons } SO_2}{\text{Yr}} \times \frac{32(S)}{64(SO_2)} \times \frac{1 \text{ Part Oil}}{0.0164 \text{ Parts S}^{**}} \times \frac{2 \times 10^3 \text{ Lb}}{\text{Ton}}$$

$$\times \frac{1 \text{ BBL}}{325 \text{ Lbs}} \times \frac{\$2.50}{\text{BBL}} = \frac{\$81 \times 10^6}{\text{Yr}}$$

*Based on hydrodesulfurization costs.

**Based on MAPS3 data.

IV. FGD for Coal Burning Boilers >75 MW_t

1. Capital Investment

Boiler Size,[a] MW_t	x	Cap. Invest.,[b] $\$10^3/MW_t$	x	# Boilers[a]	=	Total Cap. Invest., $\$10^6$
96		64		34		209
220		54		22		262
						471

Using a 1.3 retrofit factor

Total Cap Invest = $\$471 \times 10^6 \times 1.3 = \$612 \times 10^6$

2. Annual Costs

Boiler Size,[a] MW_t	x	Annual Costs[c] $\$10^3/Yr/MW_t$	x	# Boilers[a]	=	Total Annual Costs, $\$10^6/Yr$
96		22.5		34		73
220		20.0		22		97
						170

a. Table 3-5
b. Figure 5-1
c. Figure 5-2

APPENDIX III

CAPITAL INVESTMENT AND ANNUAL COSTS
FOR
NON-BOILER SO_2 EMISSIONS REDUCTION PROCESSES
IN
PLANTS EMITTING > 20,000 TON SO_2/Yr

Calculational Basis

NEDS data reported flue gas rates for each process unit in cubic meters/sec. These data were converted to boiler capacity, MW_t, as follows:

$$\underset{\text{NEDS data}}{X\ \frac{m^3}{Sec}} \times \frac{1\ MW_e}{3350\ acfm} \times \frac{3\ MW_t}{1\ MW_e} \times \frac{60\ Sec}{min} \times \frac{(3.28)^3 ft^3}{m^3} = 1.896\ (X)$$

Investment and annual costs were calculated from Figures 5-1 and 5-2 as follows:

1. Use shop-fabricated/packaged FGD investment/cost data $\leq 60\ MW_t$
2. Use field-fabricated/erected FGD investment/cost data $> 60\ MW_t$
3. 1.3 investment retrofit factor

TABLE II-1. CAPITAL INVESTMENT AND ANNUAL COSTS FOR NON-BOILER SO_2 EMISSIONS REDUCTION PROCESSES--METALS INDUSTRY (EXCLUDING BOILERS)

Site	Uncontrolled SO_2 10^3Tons/Yr Site	Uncontrolled SO_2 10^3Tons/Yr Process	Process	SO_2 Removal Technology	% SO_2 Removal	Equiv. FGD MW_e	Cap Invest $\$10^6$	Annual Cost $\$10^6$/Yr	Controlled SO_2 10^3Tons/Yr
White Pine, MI	77.2 (now at 40% Ton/Yr - 1/2 Cap)	36.6	Cu Smelting	Acid Plant + MgO FGD (a) previously estimated	87.3	-	19.6(a)	7.3(a)	9.7
		15.0	Cu Smelting						
		4.8	Cu Smelting						
		76.4							
AGARCO, TX	200.9	100.0	Cu Smelting + 40% efficient acid plant	FGD assumed installed in acid plant	90	235	12.5	4.6	10.0
		36.0	Cu Smelting (Reverb furnaces-assumed)	FGD-Dual Alkali (a) previously estimated	90	-	11.4(a)	5.3(a)	6.0
		23.5							
		37.7	Pb Smelting	Acid Plant (a) Previously estimated	98	-	8.9(a)	2.9(a)	0.8
				Fugitives cleanup (a) Previously estimated	-	-	11.9(a)	0.6(a)	
		3.7	99.0% efficient acid plant	Acid plant already installed. No FGD installation assumed	-	-	-	-	3.7
		200.9					44.7	13.4	20.5
St Joe Lead, MO		44.7 (87.9)	Pb Smelting	Acid plant already installed. FGD assumed installed on acid plant	90	440	18.9	13.3	4.8

(a) Cost estimates updated to 1980 from previously reported cost estimates[24,25]

TABLE II-1. CAPITAL INVESTMENT AND ANNUAL COSTS FOR NON-BOILER SO_2 EMISSIONS REDUCTION PROCESSES--METALS INDUSTRY (EXCLUDING BOILERS) (CONTINUED)

Site	Uncontrolled SO_2 10^3Tons/Yr Site	Uncontrolled SO_2 10^3Tons/Yr Process	Process	SO_2 Removal Technology	% SO_2 Removal	Equiv. FGD MW_e	Cap Invest $10^6	Annual Cost $10^6/Yr	Controlled SO_2 10^3Tons/Yr
Youngstown Steel, IN	79.1	72.8	Fe & Steel	FGD	90	7 units 261 MW_e ea	93.2	34.7	7.3
		1.5	Coke Mat	FGD	90	25	1.4	0.6	0.2
		1.5	Coke Mat	Uncontrolled	-		-	-	1.5
		75.8					94.6	35.8	9.0
US Steel, PA	121.4	35.1	Coke Mat	FGD	90	9 units 68 MW_e ea	21.4	11.0	3.5
		30.4	Coke Mat	FGD	90	4 units 112 MW_e ea	27.3	9.8	3.0
		18.4	Coke Mat	FGD	90	4 units 59 MW_e ea	8.3	4.2	1.8
		12.3	Coke Mat	FGD	90	3 units 68 MW_e ea	10.7	3.7	1.2
		96.2					67.7	28.7	9.6
Bethlehem Steel, MD	27.2	27.2	FE & Steel	FGD	90	644	23.8	9.7	2.7
Weirton Steel, WV	31.1	6.0	Fe & Steel	FGD	90	220	11.9	4.4	0.6
		4.3	Fe & Steel	FGD	90	88	5.5	2.0	0.4
		0.2	Steel & Coke Mat	Uncontrolled	-	-	-	-	0.2
		10.5					17.4	6.4	1.2
US Steel, IN	4.0	4.0	Fe & Steel	FGD	90	2 units 398 MW_e ea	35.8	13.7	0.4
Alcoa, TX	47.5	3.1	Al Prebake	Wet scrubbing (already installed)			-	-	3.1
		0.6	Al Prebake + PCC	Uncontrolled	-		-	-	0.6
		3.7							3.7
Inland Steel, IN	61.3	0.8	Fe & Steel	Uncontrolled	-		-	-	0.8
		543.0					323 x 1.3 = 420	128.0	62.0

TABLE II-2. CAPITAL INVESTMENT AND ANNUAL COSTS FOR NON-BOILER SO_2 EMISSIONS REDUCTION PROCESSES--PROCESS INDUSTRIES (EXCLUDING BOILERS)

Site	Uncontrolled SO_2 10^3 Tons/Yr: Site	Uncontrolled SO_2 10^3 Tons/Yr: Process	Process	SO_2 Removal Technology	% SO_2 Removal	Equiv. FGD MW_t	Cap Invest $10^6	Annual Cost $10^6/Yr	Controlled SO_2 10^3 Tons/Yr
Getty Oil, DE	37.0	13.4	Cat Cracker	FGD	90	532	21.3	8.5	1.3
		18.8	Coker	FGD	90	409	18.4	7.1	1.9
		4.8	S Plant	FGD	90	56	2.0	1.0	0.5
		37.0					41.7	16.6	3.7
Borden, FL	82.8	41.8	$PO_4^=$ Fertilizer	FGD	90	697	25.1	10.4	10.4
Texaco, TX	34.2	19.2	Process Heater	FGD	90	1080	35.6	15.4	1.9
		3.5	Process Flares	FGD	90	203	11.0	4.1	0.4
		1.3	Sludge Concentrator	FGD	90	17	1.5	0.5	0.1
		3.4	Cat Crackers	FGD	90	2 units 190 MW_t ea	21.3	7.8	0.3
		27.4					69.4	27.8	2.7
Gulf, TX	27.9	1.7	Process Heater	FGD	90	100	6.2	2.3	0.2
		10.8	S Plant	FGD	90	2 units 27 MW_t ea	3.0	1.4	1.1
		9.6	Cat Crackers	FGD	90	2 units 400 MW_t ea	36.0	13.8	1.0
		2.1	H_2SO_4	FGD	90	18	1.6	0.5	0.2
		0.4	Flares	Uncontrolled	-		-	-	0.4
		24.6					46.8	18.0	2.9

TABLE II-2. CAPITAL INVESTMENT AND ANNUAL COSTS FOR NON-BOILER SO_2 EMISSIONS REDUCTION PROCESSES--PROCESS INDUSTRIES (EXCLUDING BOILERS) (CONTINUED)

Site	Uncontrolled SO_2 10^3Tons/Yr Site	Uncontrolled SO_2 10^3Tons/Yr Process	Process	SO_2 Removal Technology	% SO_2 Removal	Equiv. FGD MW_t	Cap Invest $\$10^6$	Annual Cost $\$10^6$/Yr	Controlled SO_2 10^3Tons/Yr
Phillips, TX	27.5	5.5	Process Heater	FGD	90	309	15.1	5.4	0.6
		3.3	S Plant	FGD	90	7	0.7	0.3	0.3
		15.2	Cat Crackers	FGD	90	2 units 172 MW_t ea	19.6	7.1	1.5
		24.0					35.4	12.8	2.4
Stauffer, TX	45.2	15.7	H_2SO_4	FGD	90	96	4.8	2.1	1.6
		1.3	H_2SO_4	FGD	90	10	1.0	0.4	0.1
		4.8	H_2SO_4	FGD	90	30	1.6	0.8	0.5
		3.7	H_2SO_4	FGD	90	30	1.6	0.8	0.4
		5.9	H_2SO_4	FGD	90	33	1.7	0.8	0.6
		2.8	H_2SO_4	FGD	90	25	1.4	0.7	0.3
		7.2	H_2SO_4	FGD	90	34	1.8	0.8	0.7
		4.0	H_2SO_4	FGD	90	37	1.8	0.9	0.4
		45.4					15.7	7.3	4.5
Shell, TX	21.1	7.0	S Plant	FGD	90	39	1.8	1.1	0.7
		8.0	S Plant	FGD	90	42	1.9	1.2	0.8
		1.0	Flares	FGD	90	56	2.0	1.0	0.1
		16.0					5.7	3.3	1.6

TABLE II-2. CAPITAL INVESTMENT AND ANNUAL COSTS FOR NON-BOILER SO_2 EMISSIONS REDUCTION PROCESSES--PROCESS INDUSTRIES (EXCLUDING BOILERS) (CONTINUED)

Site	Uncontrolled SO_2 10^3Tons/Yr Site	Uncontrolled SO_2 10^3Tons/Yr Process	Process	SO_2 Removal Technology	% SO_2 Removal	Equiv. FGD Mw$_t$	Cap Invest $10^4	Annual Cost $10^4/Yr	Controlled SO_2 10^3Tons/Yr
Amoco, TX	22.4	6.4	Process Heater	FGD	90	360	16.9	6.4	0.6
		2.2	H_2SO_4	FGD	90	118	7.1	2.6	0.2
		2.2	Cat Cracker	FGD	90	35	1.7	0.8	0.2
		1.1	Cat Cracker	Uncontrolled	-	-	-	-	1.1
		11.9					25.7	9.8	2.1
Univ Atlas Cement, MO	28.6	28.6	Cement Kiln	FGD	90	505	20.7	8.2	2.9
Green Products, IA	21.6	21.6		FGD	90	694	25.0	10.3	2.2
Cities Service, LA	30.2	1.0	Process Heater	FGD	90	7	0.7	0.4	0.1
		3.1	Cat Cracker	FGD	90	165	7.6	3.5	0.3
		1.4	Process Heater	FGD	90	30	1.5	0.8	0.1
		1.2	Process Heater	Uncontrolled	-	-	-	-	1.2
		6.7					9.8	4.7	1.7
W Va Pulp & Paper, MD	26.5	7.0	Sulfite Pulping	FGD	90	164	7.5	3.5	0.7
SOHIO, OH	20.1	4.0	Flare	FGD	90	102	6.2	2.2	0.4
		4.5	Cat Cracker	FGD	90	115	6.9	2.5	0.5
		2.4	Process Heater	Uncontrolled	-	-	-	-	2.4
		10.9					13.1	4.7	3.3
Huron Cement, MI	25.7	4.7	Cement Kiln	FGD	90	132	7.9	2.8	0.5
		13.3	Cement Kiln	FGD	90	57	2.0	1.0	1.3
		2.2	Cement Kiln	FGD	90	264	13.5	5.1	0.2
		5.4	Cement Kiln	FGD	90	502	20.6	8.3	0.5
		25.6					44.0	17.2	2.5

TABLE II-2. CAPITAL INVESTMENT AND ANNUAL COSTS FOR NON-BOILER SO_2 EMISSIONS REDUCTION PROCESSES--PROCESS INDUSTRIES (EXCLUDING BOILERS) (CONTINUED)

Site	Uncontrolled SO_2 10^3Tons/Yr Site	Uncontrolled SO_2 10^3Tons/Yr Process	Process	SO_2 Removal Technology	% SO_2 Removal	Equiv. FGD MW_t	Cap Invest $\$10^6$	Annual Cost $\$10^6$/Yr	Controlled SO_2 10^3Tons/Yr
Shell, IL	30.3	1.0	Process Heater	FGD	90	46	1.7	1.0	0.1
		1.5	Process Heater	FGD	90	72	4.5	1.7	0.2
		3.4	Process Heater	FGD	90	285	14.3	5.6	0.3
		1.0	Process Heater	FGD	90	150	8.7	3.2	0.1
		1.5	Process Heater	FGD	90	197	10.8	4.0	0.2
		2.8	Process Heater	FGD	90	364	17.1	6.6	0.3
		3.0	Process Heaters	FGDs	90	2 units 45 MW_t ea	3.5	1.8	0.3
		7.3	Process Heaters	Uncontrolled	-	-	-	-	7.3
		21.5					60.6	23.9	21.5
		350.0				446.8 x 1.3 = 580		178.0	64.0